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CANADA

National Energy Board

Reasons for Decision

Husky Oil Operations Ltd.
Mobil Oil Canada, Ltd.
L & J Energy Systems, Inc.

GH-3-90

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National Energy Board

Reasons for Decision

IN THE MATTER OF

Husky Oil Operations Ltd.
Mobil Oil Canada, Ltd.
L & J Energy Systems, Inc.

Applications Under Part VI of
the *National Energy Board Act*
for Licences to Export Natural Gas

GH-3-90

October 1990

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Recital and Appearances

IN THE MATTER OF the *National Energy Board Act*, and the regulations made thereunder; and

IN THE MATTER OF the applications by Husky Oil Operations Ltd., Mobil Oil Canada, Ltd. and L & J Energy Systems, Inc. pursuant to Part VI of the *National Energy Board Act* for licences authorizing the export of natural gas.

HEARD at Ottawa, Ontario on 31 July and 1 August 1990.

BEFORE:

R.B. Horner	Presiding Member
R. Priddle	Member
C. Bélanger	Member

APPEARANCES:

J.A. Snider	Husky Oil Operations Ltd.
S. Carscallen	Mobil Oil Canada, Ltd.
L.G. Keough	L & J Energy Systems, Inc.
N.W. Boutillier	Alberta and Southern Gas Co. Ltd.
E.C. Eddy	B.C. Gas Inc.
B.J. Hodgins	CanWest Gas Supply Inc.
H.T. Soudek	Consumers' Gas Company Ltd., The
J.H. Smellie	ICG Utilities (Ontario) Ltd.
J.J. Hopwood, Q.C.	NOVA Corporation of Alberta
B. MacOdrum	Power City Partners, L.P.
K.J. MacDonald	ProGas Limited
A. Wells	Suncor Inc.
N.D. Patterson	TransCanada PipeLines Limited
D.A. Sulman G. Cameron	Union Gas Limited
E.B. McDougall	Washington Natural Gas Company
G. Toews M. Stauft	Western Gas Marketing Limited
S. Scott D. Bursey	National Energy Board

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Abbreviations

Act	*National Energy Board Act*
ALCOA	Aluminum Company of America
APP	Alternate Power Producers
BCEMPR	British Columbia Ministry of Energy, Mines and Petroleum Resources
Bcf	billion cubic feet
B.C. Gas	B.C. Gas Inc.
Board	National Energy Board
Canterra	Canterra Energy Ltd.
Cascade	Cascade Natural Gas Corporation
CNG	CNG Transmission Corporation
Consumers'	Consumers' Gas Company Ltd., The
Consumers' Buy/Sell Price	the Buy/Sell Price set out within the Large Volume Load Factor Service Rate Number 110 as published in Consumers' *Handbook of Rates and Distribution Services*
CP	CP National Corporation
DCQ	Daily Contract Quantity
DOE/FE	(United States of America) Department of Energy, Office of Fossil Energy
EARP Order	*Environmental Assessment and Review Process Guidelines Order*
EIA	Export Impact Assessment
18 CFR	(United States of America) *Title 18 Code of Federal Regulations*
EPC contract	Engineering, Procurement and Construction contract
ERCB	(Alberta) Energy Resources Conservation Board
FERC	(United States of America) Federal Energy Regulatory Commission

FS	Firm Service
Gas contract	contract for the sale and purchase of natural gas
GJ	gigajoule(s)
Husky	Husky Oil Operations Ltd.
IGC	Intermountain Gas Company
IGI	IGI Resources, Inc.
IGIP	initial gas-in-place
Iroquois	Iroquois Gas Transmission System
km	kilometre(s)
kPa	kilopascal(s)
Kraft	Kraft Inc.
LDCs	local distribution companies
LIF	limited-interruption firm
L & J	L & J Energy Systems, Inc.
MDQ	Maximum Daily Quantity
Minimum Take Level	80 percent of 20,000 MMBtu times the number of days in the year
MMBtu	million British thermal units
MMcf	million cubic feet
MW	megawatt(s)
Mobil	Mobil Oil Canada, Ltd.
Morgan	Morgan Hydrocarbons Inc.
NEB	National Energy Board
NGTL	Niagara Gas Transmission Ltd.
Niagara Mohawk	Niagara Mohawk Power Corporation
Northwest	Northwest Pipeline Corporation
NOVA	NOVA Corporation of Alberta
NYPP	New York Power Pool

NYSPSC	New York State Public Service Commission
Peaking Gas Volumes	volumes re-directed from the Power City cogeneration facility for use as system supply by St. Lawrence.
PJ	petajoule(s)
Power City	Power City Partners, L.P.
Power contract	contract for the sale and purchase of electricity
PURPA	(United States of America) *Public Utility Regulatory Policies Act of 1978*
QF	qualifying cogeneration facility
RQ Rate Schedule	CNG Transmission Corporation's full requirements Rate Schedule
S.C. No. 3 Price	price of gas sold by Niagara Mohawk to its Service Classification No. 3 customers (Large General Base Rate)
SEM	Saskatchewan Ministry of Energy and Mines
Sierra A pool	Sierra Pine Point A Pool
Sierra E pool	Sierra Pine Point E Pool
St. Lawrence	St. Lawrence Gas Company Inc.
Thermal contract	contract for the sale and purchase of steam (and chilled water in the L & J application)
TransCanada	TransCanada PipeLines Limited
TransGas	TransGas Limited
U.S.	United States of America
Union	Union Gas Limited
Washington Natural	Washington Natural Gas Company
Westcoast	Westcoast Energy Inc.

Chapter 1

Introduction

1.1 The Applications

During the GH-3-90 proceedings, the National Energy Board ("the Board") heard three applications for gas export authorizations filed under section 117 of the *National Energy Board Act* ("the Act"). The three applications for five licences were filed by the following companies:

1. Husky Oil Operations Ltd. ("Husky");
2. Mobil Oil Canada, Ltd. ("Mobil") for three separate licences; and,
3. L & J Energy Systems, Inc. ("L & J");

Details of the five applied-for licences are summarized in Table 1-1.

1.2 Market-Based Procedure

The Board, in considering an export application, must take into account the requirements of section 118 of the Act, which necessitate that the Board have regard to all considerations that appear to it to be relevant. In particular, the Board must satisfy itself that the quantity of gas to be exported does not exceed the surplus remaining after due allowance has been made for reasonably foreseeable Canadian requirements, taking account of trends in discovery.

To comply with the requirements of section 118 of the Act, the Board utilizes its Market-Based Procedure. The discussion of the Board's Market-Based Procedure that follows is general in nature and applies to each of the export applications heard in the GH-3-90 proceedings.

The Market-Based Procedure includes consideration of the following:

- complaints, if any, under the complaints procedure;
- an Export Impact Assessment ("EIA"); and,
- any other factors that the Board considers relevant to its determination of the public interest.

1.2.1 Complaints Procedure

If Canadian gas users have been unable to obtain supplies of gas under contract on terms and conditions, including price, similar to those of the proposed export, they may complain to the Board under the provisions of the Market-Based Procedure.

1.2.2 Export Impact Assessment

The purpose of the EIA is to assist the Board in determining whether a proposed export is likely to cause Canadians difficulty in meeting their future energy requirements at fair market prices. When the Market-Based Procedure was first introduced, each export applicant was required to file an EIA assessing the impact of the proposed export on domestic natural gas supply, demand, and prices, and on the ability of Canadian energy markets to adjust to these changes without difficulty.

Pursuant to a review of EIA filing requirements conducted in the fall of 1989, the Board decided that, while it would retain the EIA as part of its Market-Based Procedure, it would conduct its own non project-specific assessment. Applicants now have the option of using the Board's analysis or of preparing and submitting their own analysis as a basis for arguing whether the proposed exports would result in adjustment difficulties in Canadian energy markets.

Accordingly, each applicant in the GH-3-90 proceeding was directed to advise the Board and interested parties whether it intended to rely on the Board's most recent EIA or to submit its own EIA.

Table 1-1

Summary of Applied-for Licences

GH-3-90

Applicant	Buyer (Type of market)	Term	Export Point	Start Date	Maximum Quantities Applied-for: Daily 10^3m^3 (MMcf)	Annual 10^6m^3 (Bcf)	Term 10^6m^3 (Bcf)
1. Husky (new licence)	Power City (cogeneration plant)	1 Aug. 1992 to 1 Nov. 2007	Cornwall, Ontario	1 Aug. 1992	566.6 (20.0)	206.8 (7.3)	3 154.0 (111.3)
2. Mobil (new licence)	Cascade (system supply)	1 Nov. 1990 to 31 Oct. 2000	Huntingdon, British Columbia	1 Nov. 1990	327.5 (11.6)	119.5 (4.2)	1 195.5 (42.2)
3. Mobil (new licence)	IGI Resources (system supply)	1 Nov. 1990 to 31 Oct. 2000	Huntingdon, British Columbia	1 Nov. 1990	136.5 (4.8)	49.8 (1.8)	
				1 Nov. 1992	272.9 (9.6)	99.6 (3.5)	
				1 Nov. 1995	409.4 (14.5)	149.4 (5.3)	
							1 145.6 (40.4)
4. Mobil (new licence)	Washington Natural (system supply)	1 Nov. 1990 to 31 Oct. 2003	Huntingdon, British Columbia	1 Nov. 1990	272.9 (9.6)	99.6 (3.5)	
				1 Nov. 1992	409.4 (14.5)	149.4 (5.3)	
							1 843.0 (65.1)
5. L & J (new licence)	L & J (cogeneration plant)	15-years after commencement of firm deliveries	Iroquois, Ontario	1 Nov. 1991	329.6 (11.7)	121.3 (4.3)	1 815.9 (64.1)

1.2.3 Other Factors Relevant to the Public Interest

In addition to using the complaints procedure and the EIA outlined above to ascertain whether gas proposed to be exported is surplus, the Board continues, as required by section 118 of the Act, to have regard to all other factors it considers relevant in determining whether a proposed export is in the public interest.

Among the factors the Board considers are: evidence that the gas proposed to be exported is under contract, including full details of the nature of the supply and sales arrangements as well as copies of executed contracts; evidence of producer support for the proposed export; evidence on the status of permits to remove gas from the producing province(s) involved; evidence that export volumes will be taken; evidence that export revenues will recover fixed transportation costs incurred in making the export; evidence on the availability of pipeline space; and, on the need to build additional pipeline and other facilities in Canada and in the importing country.

In general, these factors can be placed into two categories: a) gas supply; and, b) market and commercial arrangements. This listing of factors the Board may regard as relevant is illustrative rather than exhaustive. It is intended to indicate the kind of matters the Board considers in assessing whether an export proposal is in the public interest. The onus is on the applicant to persuade the Board that it has met the requirements of section 118 of the Act.

1.2.3.1 Gas Supply

The Board conducts a review of the applicant's gas supply arrangements to assist it in determining whether the proposed export is in the public interest.

In its assessment of gas supply, the Board examines the adequacy of both reserves and productive capacity to support the applied-for exports.

Each export applicant provided estimates of remaining established reserves for those fields from which it intends to produce gas for the proposed export. The Board conducted geological and engineering analyses of each applicant's gas supply in order to prepare its own estimates of marketable gas reserves.

In its evaluation of gas reserves, the Board made use of its gas reserves database, which is maintained and updated on an ongoing basis. The evaluation of gas reserves includes a nomenclature check for correlation purposes, volumetric studies of new pools, re-examination of developing pools, and analysis of producing pools, which includes reviewing historic production and pressure data. A review and an evaluation of the ownership and contractual status of all pools included in the applications were also conducted.

The Board's approach to the assignment of reserves for single-well pools is based on extensive studies on the performance and drainage of these pools. The results of these studies were grouped by formation and area within Alberta and revealed a considerable variation in drainage areas, both regionally and by formation, with the Mannville sands having the smallest areal extent. The Board has generally adopted these results but applies them as a guideline only. In those cases where geological or other data is available which indicates that the guidelines are not appropriate, adjustments to the area assignments are reflected in the Board's reserves estimates. The Alberta Energy Resources Conservation Board ("ERCB") has also conducted a study of single-well pools and has adopted an approach to area assignments similar to that used by the Board.

The Board's approach to assignment of reserves to a discovery well and consideration of possible appreciation of reserves are consistent with the definition of established reserves. This definition makes reference to reserves specifically proven by drilling, testing or production, plus that judgment portion of reserves interpreted to exist from geological, geophysical or similar information, with reasonable certainty. Where the Board has geological or other evidence to suggest that a larger area assignment is warranted, reserves assigned to the discovery well include an estimate of appreciation. A portion of the area would generally be categorized as probable reserves and discounted by a risk factor. In addition, the Board has given consideration to potential reserves where an applicant provides evidence to demonstrate that the potential reserves would be under its control.

Estimates of reserves submitted by the applicants are for specific pools in British Columbia, Alberta, and Saskatchewan. Pool sizes varied from small, single-well pools to very large, established pools. Generally, large pools tend to have been producing for a considerable period of time, while single-well pools have often not yet been placed on production.

In reviewing marketable gas reserves, the Board evaluated the number, size, and distribution of pools for which the applicants had submitted estimates. In some cases, the Board's pool count was different from that of an applicant's because the Board amalgamated or segregated pools on the basis of its interpretation of reservoir data. All references to pool counts in the following chapters are based on the Board's analysis.

The Board's estimates of reserves, along with basic deliverability data for each of the pools for which estimates of reserves were submitted, were used in preparing productive capacity projections. Productive capacity projections are generally adjusted to reflect an applicant's expected requirements for gas. The adjusted productive capacity is the estimated productive capacity at any point in time, carrying forward for future use the productive capacity resulting from an earlier excess of productive capacity over production. The requirements included in the productive capacity figures are based on an assumed load factor of 100 percent and may therefore somewhat overstate each applicant's actual supply requirements.

1.2.3.2 Market and Commercial Arrangements

The Board conducts a review of the market and commercial arrangements underpinning a project to assist it in determining whether the proposed exports are in the public interest.

The Board's review of exports to local distribution companies ("LDCs") includes consideration of the LDCs' current and projected requirements, overall supply portfolio, and the role of the proposed export within that portfolio.

In the case of exports to cogeneration facilities, the Board's review includes examination of the contractual chain, from the gas sales contract to the power and the thermal contracts, to ensure durability[1]. Also examined are the status of project financing, construction, and qualifying cogeneration facility ("QF") certification. The criteria for QF certification are set out in section 1.3 of these Reasons for Decision.

Regardless of the type of end market, the Board's review includes consideration, amongst other items, of the load factor at which the proposed export is anticipated to flow, and the status of any regulatory authorizations and transportation arrangements which may be required for the export to proceed.

The Board's review of the commercial arrangements includes consideration of:

- the contractual commitments of the gas supply in the province(s) of production;
- the upstream and downstream transportation arrangements;
- the contractual obligations entered into between the Canadian seller and the United States of America ("U.S.") buyer;
- any resale arrangements that occur beyond the border sale point, if such arrangements could influence or affect the international sales agreement; and,
- in the case of sales to cogeneration facilities, the contractual obligations entered into between the cogeneration facility and each of the steam host and the electric utility.

The Board reviews the gas sales contracts entered into between the Canadian seller and the U.S. buyer to determine specifically whether the contracts:

- are likely to recover associated Canadian intraprovincial and interprovincial transportation costs;
- are likely to be durable over their term;
- ensure that the volumes contracted-for would likely be taken; and,

1 A cogeneration facility is defined as a facility that produces "electric energy and forms of useful thermal energy (such as heat or steam), used for industrial, commercial, heating, or cooling purposes, through the sequential use of energy". *Title 18 Code of Federal Regulations* ("18 CFR") § 292.202 (c) (1980)

- have the support of the Canadian producer(s) supplying the gas to the export project.

The Board reviews the pricing provisions of the contracts to determine whether a durable long-term arrangement, consistent with the volume and term of the applied-for licence, has been entered into. Where contracts between a Canadian seller and an export buyer have been freely negotiated at arm's length, the Board intends to intervene only in exceptional circumstances. Where the export contract is not formed at arm's length, then other contracts in the chain of arrangements between the gas producer and end-users are examined as appropriate.

1.3 Cogeneration Plants

Two of the three export applications involve the sale of gas for use by cogeneration facilities.

In each case, the proposed cogeneration facility would employ combined-cycle technology, utilizing both combustion turbine and steam turbine-driven electrical generating equipment to improve conversion efficiency. Regulations issued under authority of the (U.S.) *Public Utility Regulatory Policies Act of 1978* ("PURPA") require that a cogeneration facility, in order to maintain its QF status, must have a thermal output, as process steam, exceeding 5 percent of the total energy output of the plant. Also, the total electrical energy plus one-half of the thermal energy output must exceed 45 percent of the total energy fuel input (42.5 percent if the thermal output is greater than 15 percent). Failure to meet PURPA operating efficiencies could cause a cogeneration project to lose its QF status.

Another criterion that must be met to maintain QF status requires that the electric utility ownership in a QF must not exceed 50 percent.

The PURPA regulations require electric utilities to buy all of the electricity generated by a QF and, unless the electric utility and the QF otherwise agree, to pay the QF not more than the full avoided-cost of producing the electricity.

QF owners and electric utilities may make alternative arrangements whereby an electric utility may dispatch a cogeneration facility.[1]

In the event a cogeneration facility lost its QF status, neither the PURPA nor the implementing regulations would prevent a cogeneration facility from regaining its QF status once compliance with the criteria for qualification had been restored.

1.4 Environmental Screening (GHW-3-90)

On 8 February 1990, the Minister of Energy, Mines and Resources, the Honourable Jake Epp, wrote to the Board requesting clarification on how the Board complied, or would comply, with the *Environmental Assessment and Review Process Guidelines Order* ("EARP Order") in arriving at its decision to issue licences for the export of natural gas. In his response to the Minister, the Chairman of the Board advised that, in compliance with the EARP Order, the Board would be instituting a procedure to examine the potential environmental effects of the export proposals heard by the Board.

Environmental screening enables the Board to reach one of the conclusions required by section 12 of the EARP Order. To that end, the Board held a written hearing pursuant to Hearing Order GHW-3-90, wherein it considered submissions from the applicants and from all interested parties.

The applicants filed with the Board environmental information concerning the potential environmental effects of the proposal and the social effects directly related thereto, including any effects external to Canadian territory.

Interested parties were served with the written submissions of Husky, Mobil, and L & J and were provided with an opportunity to provide their written views on the issues referred to in those submissions. Husky, Mobil, and L & J were then afforded an opportunity to reply to the written submissions from interested parties.

The Board has completed its environmental screening and has concluded that, in respect of the export proposals of Husky, Mobil, and L & J, the potentially adverse environmental effects and the social effects directly related thereto are insignificant or mitigable with known technology or will, for certain aspects of the projects, be subject to future detailed environmental review.

1 Dispatch allows an electric utility to schedule and to control the production of electricity by a QF.

With respect to those aspects of the projects that will be subject to future detailed environmental review, the Board concludes that the review process will ensure that a complete assessment of the environmental effects will be made prior to their approval. Because of this assurance, the Board is satisfied that the issuance of the requested licences at this time will not in any way affect that subsequent examination. The Board's environmental screenings are available on request.

1.5 Sunset Clauses

It has been Board practice in issuing a gas export licence to set an initial term of the licence for a short period of time during which, if the export of gas commences, the licence becomes effective for the full period approved by the Board. Because the licence will expire if exports have not commenced within a specified timeframe, this condition in the licence is referred to as a "sunset" clause. Inclusion of the sunset clause is intended to limit outstanding licences to those for which the gas actually flows within a reasonable period after the hearing. The Board questioned each applicant concerning the acceptability of a sunset clause in the applied-for licence and the appropriateness of a particular initial term.

1.6 Completeness of Applications

Union Gas Limited ("Union") expressed concern that the Board is issuing Hearing Orders on the basis of incomplete applications and that this could lead to last minute filings of evidence and consequent difficulties for intervenors to assess the applications in a complete and timely manner. Union had also expressed this concern during previous hearings.

The Board is aware that the hearing process is more efficient when all information is complete before a Hearing Order is issued. The Board attempts to ensure that all intervenors have sufficient time to assess applications. The Board will continue to keep this in mind and will set down applications for hearing only when they are complete. This should allow better definition of issues and promote a generally more efficient hearing process.

Chapter 2

Husky Oil Operations Ltd.

2.1 Application Summary

By application dated 7 March 1990, Husky, on its own behalf and as agent for its affiliate, Canterra Energy Ltd. ("Canterra"), sought, pursuant to Part VI of the Act, a new natural gas export licence with the following terms and conditions:[1]

Term	-	commencing on 1 August 1992 and ending on 1 November 2007. Should commencement of deliveries occur after 1 November 1992, the licence term shall be 15-years, but shall in no event extend beyond 31 October 2008.
Point of Export	-	near Cornwall, Ontario.
Maximum Daily Quantity	-	566.6 10^3m^3 (20 MMcf)
Maximum Annual Quantity	-	206.8 10^6m^3 (7.3 Bcf)
Maximum Term Quantity	-	3 154.0 10^6m^3 (111.3 Bcf)
Tolerances	-	2 percent per day and 2 percent per month.
	-	any volumes authorized for export which are not actually exported during any year may be exported during the remaining term of the licence, subject to the limitations of the daily and annual volumes.[2]

The gas reserves supporting the proposed export are located in the provinces of British Columbia and Saskatchewan. These reserves are from existing pools and fields controlled by Husky. The British Columbia-sourced gas would be transported from the field to the Alberta border through a new lateral. The gas would then be transported in Alberta by NOVA Corporation of Alberta ("NOVA") to the interconnection of NOVA and TransCanada PipeLines Limited ("TransCanada") near Empress, Alberta. Transmission of the Saskatchewan-sourced gas would utilize the facilities of TransGas Limited ("TransGas"). Deliveries to TransCanada from TransGas would take place at the existing interconnection of TransGas and TransCanada near Success, Saskatchewan. From these points of interconnection, the gas would be transported on TransCanada's system to the existing interconnection between TransCanada and Niagara Gas Transmission Ltd. ("NGTL"). Gas delivered to NGTL would be transported to the international border near Cornwall. At this point, Power City Partners, L.P. ("Power City") would obtain ownership of the gas. The gas would then be shipped on the St. Lawrence Gas Company ("St. Lawrence") system to the vicinity of Power City's cogeneration facility at Massena, New York. Local transportation from the St. Lawrence system to the facility would require construction of a short pipeline.

The plant's power output would be sold to Niagara Mohawk Power Corporation ("Niagara Mohawk") and the steam would be sold to the Aluminum Company of America ("ALCOA").

2.2 Complaints Procedure

The complaints procedure gives Canadian gas users an opportunity to object to an export proposal on the grounds that they have not had an opportunity to obtain supplies of gas under contract terms and conditions, including price, similar to those contained in the export proposal.

No complaints were received with respect to the Husky export proposal.

2.3 Export Impact Assessment

Husky elected to rely on the Board's most recent EIA, published 7 September 1989, with the caveat

1 References herein to Husky are to Husky and Canterra collectively, except when the context requires otherwise.

2 During the hearing, Husky agreed with the Board that such a condition was not operable and requested that the condition be deleted from its application.

that it would reserve the right to prepare and submit its own analysis should the Board's analysis determine that further gas exports would result in adjustment problems in Canadian energy markets. No such problems were identified during the hearing process.

The Board's EIA indicates that the applied-for export volumes would have little impact on the production, consumption, and price of gas in Canada, and that Canadian energy users would not experience difficulty in meeting their future energy requirements as a result of the proposed export.

2.4 Gas Supply

2.4.1 Supply Contracts

Husky submitted a list of pools from which it intends to provide the required volumes for the proposed export to Power City. Since Husky intends to supply the proposed export with gas from its own pools, no gas supply contracts were required. The Board notes that no specific pools have been contractually dedicated to the proposed export and that the gas could be supplied from the company's general supply pool.

2.4.2 Reserves

Table 2-1 shows that the Board's estimate of Husky's contracted remaining marketable gas reserves is 7 percent lower than Husky's estimate. The Board's estimate exceeds the applied-for volume by 12 percent.

Table 2-1

Comparison of Estimates of Husky's Remaining Marketable Gas Reserves with the Applied-for Term Volume

10^6m^3
(Bcf)

Husky[1]	NEB[1]	Applied-for Volume
3 791	3 520	3 154
(134)	(124)	(111)

1 As of December 1989

Husky submitted data on gas reserves in the Boundary Lake Field of British Columbia and the Celtic and Tangleflags Fields of Saskatchewan in support of its application. Husky's reserves in the Boundary Lake Field are located in the Belloy and Kiskatinaw Formations. The Celtic and Tangleflags reserves are found in Cretaceous sands. Differences in estimates of reserves arise from relatively small differences in interpretation of area, net pay, and other reservoir parameters.

In its analysis of Husky's gas supply, the Board recognized 18 gas pools, of which eight are currently not producing. Ninety-one percent of the total reserves come from nine pools larger than 100 10^6m^3 (3.5 Bcf) in size, seven of which are located in the Boundary Lake Field.

In summary, the Board's estimate of reserves is similar to that of Husky's, and exceeds the applied-for volume. The difference in estimates of reserves arises from the cumulative effect of small differences in several reservoir parameters.

2.4.3 Productive Capacity

A comparison of both the Board's and Husky's projections of productive capacity to the applied-for volumes, inclusive of fuel and shrinkage, is shown in Figure 2-1.

Husky's projection indicates adequate productive capacity until 2005, whereas the Board's projection suggests adequate supply until 2001, with the magnitude of the shortfall increasing throughout the remainder of the term. This difference in projections is due primarily to differences between the Board's and Husky's estimates of reserves.

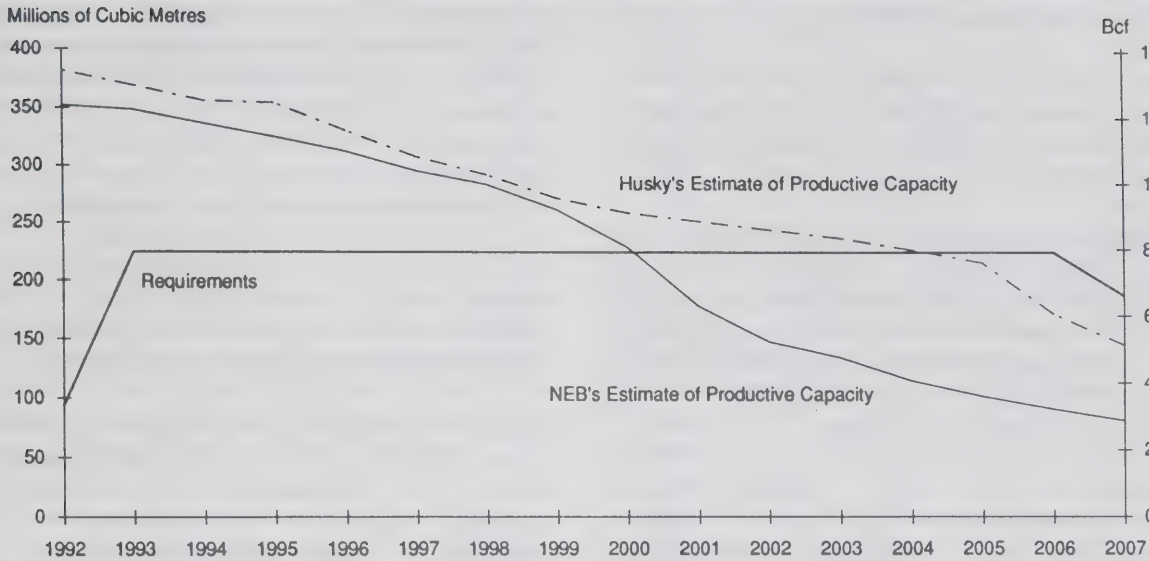
Husky stated that, if necessary, it could rely on its corporate gas supply to alleviate deliverability shortfalls. In this regard, Husky stated that it currently had approximately 3 100 10^6m^3 (110 Bcf) of uncontracted gas reserves.

2.4.4 Energy Removal Authorization

Husky has applied to the British Columbia Ministry of Energy, Mines and Petroleum Resources ("BCEMPR") and the Saskatchewan Ministry of Energy and Mines ("SEM") for energy removal authorizations from those provinces.

Figure 2-1

COMPARISON OF NEB'S & HUSKY'S ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY



BCEMPR has advised Husky that it is satisfied that Husky has dedicated sufficient reserves to support the volumes requested in its application for an energy removal certificate.[1] A decision for an energy removal permit from SEM is pending.

2.4.5 Views of the Board

The Board's estimate of reserves for the specific pools submitted by Husky in support of its application exceed the applied-for volume. However, the Board's assessment of Husky's productive capacity indicates deficiencies relative to requirements over the latter portion of the proposed export term. The Board considered the evidence Husky provided regarding its uncommitted corporate supply and is of the view that any shortfalls in productive capacity would be remedied by Husky's corporate gas supply. The Board is therefore satisfied as to the adequacy of the gas supply available for the proposed export.

2.5 Market and Commercial Arrangements

2.5.1 Market

The gas proposed for export would be used to fuel a 79 MW natural gas-fired cogeneration facility that Power City plans to construct in Massena, New York. Power City is a Delaware limited partnership, the partners in which are Power City Generating, Inc., as general partner, and Energy Factors Incorporated and Sundance Energy Ltd. as limited partners.

The cogeneration facility would be located at the ALCOA plant site in Massena, New York. The ALCOA plant, the steam purchaser, is an integrated smelting and fabricating facility producing approximately three-quarters of a million pounds of molten aluminum daily and manufacturing aluminum wire, rod, and bar. Niagara Mohawk, the power purchaser, provides electric service to more than 1.4 million residential, commercial and industrial customers, and has a peak electrical demand exceeding 6,200 MW. Its four major markets are Buffalo, Syracuse, Albany, and Watertown. Reduced power availability from the New York Power Authority and increasing load growth require Niagara Mohawk to procure addi-

1 Subsequent to the close of the hearing, Husky, by letter dated 17 September 1990, informed the Board that it had received Energy Removal Certificate 36(9008) from BCEMPR. The removal certificate expires on 1 November 2007 and allows Husky to remove up to 2 708 $10^6 m^3$ (96 Bcf) of natural gas from British Columbia.

tional power from other sources, including cogeneration facilities.

Construction of the cogeneration facility was anticipated to commence by early summer 1990 and be completed by the summer of 1992.

At the time of the hearing, Power City was arranging final project financing, which it expected to secure before year's end. The interim financier is Sythe Energies U.S.A.

All required environmental approvals and permits in the U.S. with respect to the construction and operation of the cogeneration facility are expected by the fall of 1990. The decision on the application to the (U.S.) Department of Energy, Office of Fossil Energy ("DOE/FE") for import authorization was pending at the time of the hearing.

Application to the (U.S.) Federal Energy Regulatory Commission ("FERC") for QF certification was to occur after the Engineering, Procurement and Construction contract ("EPC contract") was finalized. Negotiations on the EPC contract were expected to be completed by the end of August. Husky indicated that no problems were anticipated with Power City's QF certification and undertook to file proof of certification with the Board upon receipt.

The load factor of the Power City facility over the term of the applied-for export was estimated by the applicant to be 93 percent. The Power City facility, under the terms of the Natural Gas Purchase Agreement, is to purchase its minimum gas requirements exclusively from Husky, and is to use No. 2 fuel oil as the back-up fuel. In order to comply with New York State air permit regulations, the cogeneration facility would not be permitted to burn oil more than 10 percent of the time.

2.5.2 Transportation

British Columbia-sourced gas would be shipped by pipeline to Alberta. Within Alberta, the gas would be shipped to Empress on the NOVA system. Saskatchewan-sourced gas would be shipped on TransGas to Success. TransCanada would transport the gas from these points to the NGTL system for delivery to the St. Lawrence system. St. Lawrence would then deliver the gas to the cogeneration facility in Massena, New York.

Transportation from the Boundary Lake reserves in British Columbia to the NOVA inlet would occur through a 25 km pipeline to be constructed by Placer CEGO Petroleum Inc. and Husky. The necessary applications for regulatory authorizations to construct this lateral are expected to be filed in the fall of this year. Transportation in Alberta has been secured under a nine-year firm transportation agreement between NOVA and Husky. Transportation from the field in Saskatchewan to the TransCanada system would occur on TransGas' system under contracts of five-years duration.

Husky indicated that it intended to rely on the renewal rights provisions in the NOVA and TransGas service agreements for firm transportation beyond that presently contracted-for.

Power City entered into a Precedent Agreement dated 30 March 1989 with TransCanada for Firm Service ("FS") transportation. Power City's transportation rights on TransCanada are to be assigned to Husky upon commencement of firm deliveries. Husky stated that it would seek to amend the termination date presently in the Precedent Agreement to accommodate the issuance of the licence. Facility additions required on TransCanada to provide FS transportation were approved in the GH-1-89 Hearing.

Interim use of the capacity on TransCanada's system would be made by sales from Husky to The Consumers' Gas Company Ltd. ("Consumers' "). During these sales, Husky would have the FS contract for transportation on TransCanada assigned to it.

Firm transportation on NGTL is being arranged on Husky's behalf by Power City. Transportation on St. Lawrence would occur under an interruptible agreement to be entered into by St. Lawrence and Power City. Husky undertook to provide the Board with executed copies of the transportation agreements with NGTL and St. Lawrence.

The pipeline interconnection, to be constructed by St. Lawrence between its existing system and the cogeneration facility, has not yet been approved by the New York State Public Service Commission ("NYSPSC"). The proponents do not anticipate any difficulty in receiving NYSPSC approval.

Additional facilities would not be required on the NOVA, TransGas, or NGTL systems.

2.5.3 Gas Sales Contract

A Natural Gas Purchase Agreement ("gas contract") dated 15 February 1990 has been executed by Husky and Power City and was filed with the Board. The gas contract is for a term of fifteen years commencing from the date of first firm deliveries and provides for the daily delivery of up to 566.6 10^3m^3 (20 MMcf) of gas at the Cornwall, Ontario delivery point.

The gas contract is subject to several conditions precedent, including: receipt of all Canadian and U.S. regulatory approvals; finalization of all Canadian and U.S. transportation arrangements; buyer obtaining commitment for buyer's financing upon reasonable terms; and buyer providing Notice to Proceed to the contractor. The conditions precedent are to be satisfied by 1 May 1991 otherwise either party may terminate the gas contract.

The gas contract provides for deliveries of start-up gas prior to the commencement of firm deliveries. If deliveries have not commenced by 1 November 1992, the gas contract terminates unless the buyer requests an extension. Deliveries must, however, commence by 1 November 1993 at the latest in the event of an extension.

In the event that the buyer takes less than 16,000 MMBtu per day on average over two consecutive contract years ("Minimum Take Level"), the buyer shall pay a specified reservation fee not in excess of U.S. $500,000 for those two years. Should Power City nominate less than the Maximum Daily Quantity ("MDQ") of 566.6 10^3m^3 on any day, Husky has the option to sell to third parties any portion of the MDQ not taken by Power City. The gas contract also stipulates that Power City shall not take less than the Minimum Take Level from Husky by reason of Power City having access to gas supplies from third parties.

In the event that St. Lawrence interrupts transportation to the cogeneration facility, purchasing such interrupted supply for use on its own system ("Peaking Gas Volumes"), Power City has agreed to assign to Husky the right to sell these Peaking Gas Volumes to St. Lawrence.

The export price, which is set on an annual basis, is comprised of demand and commodity charge components. The demand charge is the sum of the demand and commodity charges paid by Husky for transportation on NOVA and/or TransGas and TransCanada for delivery of the gas to the Cornwall, Ontario export point.

The commodity charge component is adjusted annually from an initial level of $ U.S. 1.58/GJ ($ U.S. 1.65/MMBtu) during the calendar year 1991. Adjustments to the commodity charge are comprised 70 percent by changes in the Large Volume Load Factor Service Rate Number 110 Buy/Sell Price published in Consumers' *Handbook of Rates and Distribution Services* ("Consumers' Buy/Sell Price") net of TransCanada and NOVA firm transportation tolls and fuel costs, and 30 percent by changes in the twelve month average price of gas sold by Niagara Mohawk to its Service Classification No. 3 customers (Large General Base Rate) ("S.C. No. 3 Price") net of CNG Transmission Corporation ("CNG") and Niagara Mohawk firm transportation tolls and fuel costs.

Husky has indicated that there is provision for amendment to the contract upon mutual consent of both parties. Should there not be mutual agreement, any dispute could be resolved under the arbitration provisions of the contract.

Husky submitted that, on 1 January 1990, the British Columbia border price would have been $ Cdn. 1.89/GJ ($ Cdn. 1.80/MMBtu) and that the Saskatchewan border price would have been $ Cdn. 2.07/GJ ($ Cdn. 1.97/MMBtu).

2.5.4 Power Sales Agreement

The proposed sale of electricity from the Massena cogeneration facility would be pursuant to the Power Purchase Agreement ("power contract") dated 15 September 1988, as amended, between Power City Generating, Inc. and Niagara Mohawk. The power contract continues for a period of twenty years from the commercial operation date, with annual renewal thereafter until terminated by either party.

The cogeneration facility is a base load facility, requiring Niagara Mohawk to purchase its total net electrical output. Base load operation of the cogeneration facility requires Niagara Mohawk to pay the applicable energy charge based on Niagara Mohawk's avoided costs, as approved by the NYSPSC. The sale of electricity from the Massena facility does not require wheeling by third parties.

2.5.5 Curtailment

Union stated that, while NYSPSC decisions appear to have rendered contractual curtailment provisions inoperable, the issue of curtailment persists because there are still provisions for Niagara Mohawk to apply to the NYSPSC to curtail delivery from cogeneration facilities. Union stated further that no evidence had been presented that absolutely assured the Board that there would be no curtailment.

The NYSPSC issued an Order dated 27 June 1989, Case 88-E-081, which rejected, in part, Niagara Mohawk's power contract curtailment clauses with Power City. Case 88-E-081 states that curtailment of deliveries from alternative power producers may be curtailed pursuant to a provision of the PURPA Regulations, "which permit utilities to curtail, when due to operational circumstances purchases from QF's would result in costs greater than those which the utility would incur if it did not make such purchases."[1] Such operational circumstances were found to exist when a utility would curtail generation from its own must-run units during a light load period in order to take generation from Alternate Power Producers ("APP"). Once curtailed, such units would not be available to generate when load would rise from the low load point toward a day's peak load. Instead of avoiding costs, a utility would incur additional costs in securing substitutes for unavailable must-run generation. To avoid such a situation, 18 CFR § 292.304 (f) permits a utility to curtail deliveries from APPs and continue to operate its own must-run facilities.

The NYSPSC found that no utility had successfully demonstrated that operational circumstances would actually occur, creating negative avoided costs, and that, therefore, curtailment clauses were premised on assumptions that do not comport with § 292.304 (f).

The NYSPSC found that the utilities, members of the New York Power Pool ("NYPP"), assumed that their systems were operating in isolation and that they did not recognize the possibility of off-system sales to other pool members. Utilities would be required to show that the NYPP could not absorb the electricity before they would be allowed to curtail. The NYSPSC stated that, once off-system sales were recognized, the justification for curtailment vanished.[2]

After 1994, the process of bidding should match APP capacity additions to utility capacity needs. The NYSPSC assumed that generation secured through bidding would be dispatchable, enhancing utility capability to alleviate overgeneration situations without incurring curtailments due to operational circumstances.

The NYSPSC found that, because utilities were unable to demonstrate that negative avoided costs due to operational circumstances would exist from the date of 88-E-081 to 1994, and with the commencement of a bidding process in 1994, there would be a match of new sources of generation supply to generation need. Consequently, because of the operational flexibility due to greater dispatchability, there is no justification for curtailment after 1994. Since utilities failed to demonstrate they can satisfy conditions established in § 292.304 (f) justifying curtailment, the curtailment clauses were rejected and the utilities were barred from implementing them.

In a further Order dated 12 December 1989, the NYSPSC clarified its Order in Case 88-E-081. Clarification was required to ensure utilities were accorded their § 292.304 rights. The NYSPSC stated that curtailment would not be allowed until prior written approval of curtailment procedures had been obtained, following NYSPSC review of a utility's presentation. To the extent that current contract clauses deviated from the interpretation and implementation of § 292.304 (f) in the NYSPSC's proceedings, the clauses were declared null and void. However, utilities were told that they may include curtailment language which comports with NYSPSC Orders in future contracts, but that they may not expand upon the presumptions established in the NYSPSC's proceedings.

2.5.6 Thermal Energy Sales Agreement

The proposed sale of steam from the Massena cogeneration facility would be pursuant to the Steam Purchase Agreement ("thermal contract")

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1 18 CFR § 292.304 (f) (1).

2 NYSPSC staff analyzed pool wide operations to assess APP generation state-wide during light load hours. At APP penetration below 5,000 MW, utilities would not be required to curtail delivery from their must-run units. Significant curtailment would be necessary only if 7,000 MW were assumed. Utilities expected only 3,096 MW of APP generation by 1995.

dated 6 April 1989 between ALCOA and Power City. The thermal contract continues for a period of sixteen years from the commencement date of steam delivery and may be renewed for a single four-year term.

ALCOA is obligated to purchase sufficient quantities of steam so that the cogeneration facility would maintain its PURPA QF status. The thermal contract provides for the development of alternative steam uses if ALCOA's steam requirements fall below the minimum quantity required to maintain PURPA QF status. A cash penalty clause, requiring payments by ALCOA, is in effect for the first ten years. The thermal contract also requires Power City to reactivate the existing ALCOA facility to produce all or part of the steam required by ALCOA if steam from the cogeneration facility is not available.

2.5.7 Views of the Board

The Board concludes that the downstream markets for the electricity and steam produced by the cogeneration facility are secure and that the facility would operate at a high load factor.

The Board notes that final project financing, QF certification, DOE/FE import authorization, and execution of the EPC contract have not yet been completed. The Board is of the view that these are likely to be obtained.

The Board notes that evidence of secure FS transportation on NOVA, TransGas, and TransCanada has been provided and that the agreements with NGTL and St. Lawrence are expected to be submitted shortly.

The Board is satisfied that Husky's export proposal would recover all fixed costs of transportation in Canada. The demand charge component of the price in the gas contract ensures that demand charges on NOVA, TransGas, and TransCanada would be recovered.

The Board is satisfied that the index mechanism in the contract permits the export price to respond to changing market conditions. In this regard, the Board notes that, while explicit provision for renegotiation and arbitration of the pricing terms is not present in the gas contract, price renegotiation and arbitration are possible under other sections of the contract.

In the Board's view, the contract provision assuring Husky as the sole gas supplier coupled with the likely prospect that the cogeneration facility would operate at a high load factor would ensure adequate take levels under the gas contract.

The Board concurs with Union that, from the evidence presented, the Board cannot be absolutely assured that there would be no curtailment of power sales. However, the Board is of the opinion that the likelihood of curtailment of electricity purchases by Niagara Mohawk from Power City is minimal. Furthermore, the possibility of curtailment is unlikely to affect the take of gas proposed for export, and, should curtailment occur, it would likely occur for short periods only. In view of this, the Board is of the opinion that curtailment is not a critical issue.

The Board has reviewed the Natural Gas Purchase Agreement and finds that the price arrangements are such that the arrangement is likely to be durable over the contract/licence term. The Board notes that negotiations between Husky and Power City occurred at arm's length.

2.6 Disposition

The Board has decided to issue a new gas export licence to Husky subject to the approval of the Governor in Council.[1] Appendix II outlines the terms and conditions of the licence, including a condition that the term of the licence shall commence on the date that Governor in Council approval is received and shall end on 1 November 1993, unless exports commence under the licence on or before 1 November 1993, in which case the term would end on 1 November 2007 subject to the term of the licence being fifteen years following commencement of deliveries should commencement of deliveries occur after 1 November 1992. In no event shall the term extend beyond 31 October 2008. The Board notes that Husky has agreed to the 1 November 1993 sunset date.

1 In view of the fact that Husky would be acting in its own right and as agent for Canterra Energy Ltd., the licence will identify Husky in this dual role.

Mobil Oil Canada, Ltd.

3.1 Application Summary

By application dated 21 December 1989, as amended, Mobil Oil Canada, Ltd., as managing partner for the general partnership of Mobil Oil Canada, applied under Part VI of the Act for three new natural gas export licences, one for each of its sales to Cascade Natural Gas Corporation ("Cascade"), IGI Resources, Inc. ("IGI"), and Washington Natural Gas Company ("Washington Natural"), with the following terms and conditions:

a) **Cascade;**

Term	-	1 November 1990 to 31 October 2000
Point of Export	-	near Huntingdon, British Columbia
Maximum Daily Quantity	-	327.5 10^3m^3 (11.6 MMcf)
Maximum Annual Quantity	-	119.5 10^6m^3 (4.2 Bcf)
Maximum Term Quantity	-	1 195.5 10^6m^3 (42.2 Bcf)
Tolerances	-	Any adjustments to the export licences which may be necessitated by variation in the actual heating conversion factor.

b) **IGI;**

Term	-	1 November 1990 to 31 October 2000
Point of Export	-	near Huntingdon, British Columbia
Maximum Daily Quantity	-	1 November 1990 to 31 October 1992 136.5 10^3m^3 (4.8 MMcf)
	-	1 November 1992 to 31 October 1995 272.9 10^3m^3 (9.6 MMcf)
	-	1 November 1995 to 31 October 2000 409.4 10^3m^3 (14.5 MMcf)
Maximum Annual Quantity	-	1 November 1990 to 31 October 1992 49.8 10^6m^3 (1.8 Bcf)
	-	1 November 1992 to 31 October 1995 99.6 10^6m^3 (3.5 Bcf)
	-	1 November 1995 to 31 October 2000 149.4 10^6m^3 (5.3 Bcf)
Maximum Term Quantity	-	1 145.6 10^6m^3 (40.4 Bcf)
Tolerances	-	Any adjustments to the export licences which may be necessitated by variation in the actual heating conversion factor.

c) **Washington Natural;**

Term	-	1 November 1990 to 31 October 2003
Point of Export	-	near Huntingdon, British Columbia
Maximum Daily Quantity	-	1 November 1990 to 31 October 1992 272.9 10^3m^3 (9.6 MMcf)
	-	1 November 1992 to 31 October 2003 409.4 10^3m^3 (14.5 MMcf)
Maximum Annual Quantity	-	1 November 1990 to 31 October 1992 99.6 10^6m^3 (3.5 Bcf)
	-	1 November 1992 to 31 October 2003 149.4 10^6m^3 (5.3 Bcf)
Maximum Term Quantity	-	1 843.0 10^6m^3 (65.1 Bcf)
Tolerances	-	Any adjustments to the export licences which may be necessitated by variation in the actual heating conversion factor.

The gas reserves supporting the proposed export are located in British Columbia and are from existing pools controlled by Mobil. The gas would be transported on the Westcoast Energy Inc. ("Westcoast") system from the plant to the export point near Huntingdon, at which point the three purchasers, Cascade, IGI, and Washington Natural, would obtain ownership of the gas. The gas would then be transported on the Northwest Pipeline Corporation system ("Northwest").

Mobil gas purchased by the LDCs Cascade and Washington Natural would be used as system supply. The gas purchased by IGI, a fully integrated natural gas supply and customer service organization, would be used primarily to meet the system supply requirements of two of its client LDCs; Intermountain Gas Company ("IGC"), and CP National Corporation ("CP").

3.2 Complaints Procedure

The complaints procedure gives Canadian gas users an opportunity to object to an export proposal on the grounds that they have not had an opportunity to obtain supplies of gas under contract terms and conditions, including price, similar to those contained in the export proposals.

In this hearing, there were no complaints filed by intervenors pursuant to the Board's complaints procedure. The record did include, however, correspondence from B.C. Gas Inc. ("B.C. Gas") indicating that it had considered filing evidence in opposition to the export by Mobil. Negotiations subsequently took place between B.C. Gas and Mobil in which B.C. Gas concluded that Mobil had acted in good faith to provide meaningful volumes of gas to British Columbia's domestic market.

3.3 Export Impact Assessment

Mobil elected to rely on the Board's most recent EIA, published 7 September 1989. No potential adjustment difficulties in Canadian energy markets were identified during the hearing process.

Based on its most recent EIA, the Board concludes that the applied-for export volumes would have little impact on the production, consumption, and price of gas in Canada, and that Canadian energy users would not experience difficulty in meeting future energy requirements as a result of the proposed exports.

3.4 Gas Supply

3.4.1 Supply Contracts

Since Mobil intends to supply the proposed export from its own reserves in the Sierra Pine Point A Pool ("Sierra A pool") in northeastern British Columbia, no gas supply contracts exist. The Board notes that, although Mobil has stated its intention to supply the required volumes solely from the Sierra A pool, it is not contractually obligated to do so.

3.4.2 Reserves

Table 3-1 compares estimates by Mobil and the Board of remaining marketable gas reserves at 1 November 1990 in the Sierra A pool.

The Board conducted its own independent calculations of the pool's initial and remaining established reserves and has closely monitored the performance of the Sierra A pool for more than ten years. During this time, the Board has also reviewed various industry reserves estimates for the pool.

Because of often-conflicting data, the relative complexity of the behavior of the Sierra A pool reservoir, and significant differences in estimates of reserves derived using the volumetric and material balance approaches, the Board considered it appropriate in this circumstance to provide a range of estimates of reserves for the pool.

The Board's estimates of remaining reserves obtained using the material balance and volumetric methodologies are lower than those of Mobil's by 23 percent and 17 percent respectively. In both cases, however, the Board's estimates of reserves exceed the applied-for volume. A technical discussion outlining the basis for the Board's estimate of reserves for the Sierra A pool is provided in Appendix I.

It should be noted that Mobil submitted that the material balance technique is a more reliable approach for reserves determination in this pool and that Mobil provided its volumetric estimate for comparative purposes only.

Table 3-1

Comparison of Estimates of Mobil's Remaining Marketable Gas Reserves with the Applied-for Term Volume; at 1 November, 1990

10^6m^3

(Bcf)

	Mobil	NEB	Applied-for Volume
Material Balance	10 240[1]	7 895[3]	4 184
	(363)	(279)	(149)
Volumetric	6 170	5 090[4]	
	(219)[2]	(180)	

1 This estimate was derived from Mobil's material balance estimate of 38 683 10^6m^3 (1,373 Bcf) initial gas-in-place ("IGIP"), cumulative raw gas production of 13 977 10^6m^3 (496 Bcf) to 23 May 1990, estimated production from 24 May to 31 October 1990 of 300 10^6m^3 (10.6 Bcf), and Mobil's recovery factor of 70 percent and total shrinkage factor of 20 percent.

Mobil provided an estimate of cumulative raw gas production of 13 977 10^6m^3 (496 Bcf) to 23 May 1990. The Board estimated raw gas production of 300 10^6m^3 (10.6 Bcf) from 24 May to 31 October 1990 in order to provide an estimate of reserves as of 1 November 1990.

2 This estimate was derived from Mobil's volumetric estimate of 31 411 10^6m^3 (1,115 Bcf) IGIP (excluding the Sierra Pine Point E Pool ("Sierra E pool") reserves), estimated cumulative raw gas production of 14 277 10^6m^3 (507 Bcf) to 1 November 1990, and Mobil's recovery factor of 70 percent and shrinkage factor of 20 percent.

3 This estimate was derived from the Board's material balance estimate of 33 116 10^6m^3 (1,325 Bcf) IGIP, estimated cumulative raw gas production of 14 277 10^6m^3, (571 Bcf) a shrinkage factor of 20 percent and an overall recovery factor in the range of 75 percent.

4 This estimate was derived from the Board's volumetric estimate of 27 545 10^6m^3 (1,102 Bcf), estimated cumulative raw gas production of 14 277 10^6m^3 (571 Bcf), a shrinkage factor of 20 percent and an overall recovery factor in the range of 75 percent.

3.4.3 Productive Capacity

Figure 3-1 compares the Board's and Mobil's projections of productive capacity with the applied-for volumes. Mobil assumed that a source of sweet gas for plant and future compressor fuel requirements would be available.

The Board's projection of productive capacity is based on the mid-point of its material balance and volumetric reserves estimates and is consistent with the requirements shown in Figure 3-1. Mobil's estimate of productive capacity is based on an earlier projection of requirements, which was higher than that shown in Figure 3-1.

Initially, both the Board's and Mobil's projections of productive capacity far exceed the applied-for volumes, as the highly productive dolomite facies continues to be depleted. However, the two projections diverge beginning in the mid-1990's. This is attributable to the Board's lower estimate of reserves in the dolomite facies, and hence, an increasing proportion of deliverability being provided from the much less productive limestone facies. Mobil's projection of productive capacity is solely based on the highly productive dolomite facies and exceeds the applied-for volumes throughout the proposed export terms. The Board's projection of productive capacity, while lower than that of Mobil, also exceeds requirements throughout the proposed export term. Mobil also submitted that, should shortfalls in productive capacity occur, it could rely on supply from other pools in the area and on future exploration discoveries.

3.4.4 Energy Removal Authorization

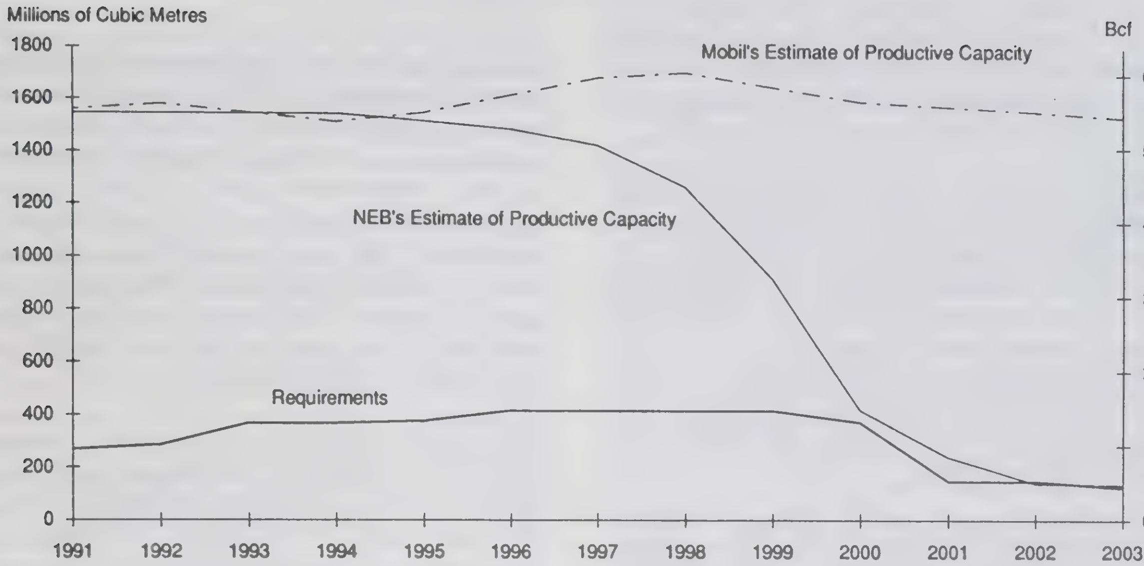
On July 30, 1990 Mobil received Energy Removal Certificates 30(9007), 31(9007), and 32(9007) from BCEMPR, which authorize it to remove the applied-for volumes from British Columbia.

3.4.5 Views of the Board

Diverse estimates of reserves for the Sierra A pool have been made on the basis of analyses conducted by Mobil and the Board. While the Board recognizes the difficulty in obtaining a reliable estimate of reserves for this pool, it considers the range provided by its material balance and volumetric estimates to be a reasonable basis on which to evaluate the proposed export application. This range of estimates of reserves is lower than Mobil's material balance estimate but encompasses Mobil's volumetric estimate of reserves. For reasons discussed in Appendix I, the Board does not consider Mobil's material balance analysis to be an appropriate basis on which to determine established reserves for the pool at this time. In particular, the Board finds Mobil's conclusion that water influx is not measurably affecting pool performance to be inconsistent with other data

Figure 3-1

COMPARISON OF NEB'S & MOBIL'S ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY



which indicates that the gas/water contact is continuing to rise and that water production from the pool is increasing. The Board is also concerned that the pool recovery factor may be negatively affected by increasing water production.

Projections of productive capacity for the Sierra A pool are highly dependent on both the magnitude and distribution of remaining reserves for the pool, both of which are rather uncertain. The Board's projection of productive capacity differs considerably from that of Mobil in the later years of the proposed export terms, but indicates that supply would be adequate to meet requirements.

While recognizing the difficulty involved in assessing reserves and productive capacity for this pool, the Board is satisfied with Mobil's supply position based on the specific pool information which has been provided. The Board also recognizes that Mobil could rely on other supply sources to offset any deficiencies in supply which may arise from poorer than anticipated pool performance.

3.5 Market and Commercial Arrangements

3.5.1 Market

Mobil applied to export gas to three purchasers: Cascade, IGI and Washington Natural. Cascade and Washington Natural are LDCs and would use the gas for system supply. Gas sold to IGI would be primarily for resale to two of its client LDCs; IGC and CP.

In October 1988, Northwest terminated its long-term export contract with Westcoast. Since that time, the three purchasers, who had previously bought gas, or whose client LDCs had previously bought gas from Northwest, have been purchasing gas under short-term agreements with Mobil. The three purchasers are now desirous of converting those short-term agreements into long-term agreements.

Cascade

Cascade is a regulated public utility engaged in the distribution and sale of natural gas in communities in eastern and western Washington and central and eastern Oregon. In September 1989, Cascade billed a total of 91,136 customers of which 75,360 were residential, 17,363 were commercial, 384 were industrial and 29 were institutional.

In 1988, Cascade's total end-use markets consumed 50.6 PJ (48.0 million MMBtu) of gas. Only marginal increases in Cascade's residential and commercial market segments are anticipated. Because of the forecasting uncertainty, no change to existing demand was projected for either of the industrial or institutional sectors. Cascade projects that the total energy demand of its end-use markets would increase to 51.9 PJ (49.2 million MMBtu) by the year 2000.

Historically, Cascade's sole gas supplier has been Northwest. Since 1985, however, Cascade has been diversifying its supply sources. The applied-for volumes, currently flowing under short-term order, are intended to augment the other firm purchases Cascade currently makes from Northwest, Canadian Hydrocarbons Energy Marketing, and Williams Gas Marketing. In 1991, the export by Mobil, assuming a 75 percent load factor, would comprise about 7 percent of Cascade's total supply.

Cascade stated that the anticipated load factor of purchases from Mobil during the licence term would be no less than 75 percent. Cascade based this estimate on actual takes over the last two years.

Cascade stated that it had a DOE/FE blanket authorization, expiring June 1991, under which the export could flow, and stated that it anticipated to file an application for import authorization with volumes and terms specific to the Mobil purchase with the DOE/FE in August 1990.

IGI

IGI is a fully integrated natural gas supply and customer service organization serving the western U.S. It currently serves over 150 industrial end-users, two broker-marketers and four LDCs. Its focus is on LDCs and industrial end-users with concentration upon the industrial end-users behind the IGC and CP systems. The proposed export would be primarily used to meet the system supply requirements of IGC but would also be used to serve CP. IGI and IGC are wholly-owned subsidiaries of Intermountain Gas Industries Inc. of Boise, Idaho.

IGC serves 105,000 customers in 70 communities located across the breadth of southern Idaho. The service area's economy is based primarily upon agriculture and related industries. Approximately 91,000 residential and 14,000 commercial customers are on-line. The approximately 87 industrial customers accounted for 59 percent of the demand in fiscal 1988. Industrial demand for gas is strongly influenced by the agricultural economy. Some gas is used as feedstock in the production of chemical fertilizers.

Historically, IGC's gas supply source was Northwest. Following Northwest's 10 June 1988 acceptance of a blanket certificate for open access transportation under FERC Orders 436 and 500, IGI has been acting as IGC's sole gas procurement agent. The majority of the purchases on IGC's behalf have been mid- to long-term contracts supplemented with periodic spot market supplies.

IGI furnished a gas supply and requirements forecast for IGC and for CP for the period through to the year 2000. In 1988, total energy consumption by IGC's and CP's end-use markets were 31.0 PJ (29.4 million MMBtu) and 6.6 PJ (6.26 million MMBtu) respectively. Total energy consumption by the year 2000 is anticipated to be 41.5 PJ (39.4 million MMBtu) and 9.6 PJ (9.09 million MMBtu) respectively.

IGI advised that a load factor of approximately 85 percent is anticipated. At this load factor, the export by Mobil would be approximately 4 percent of IGC's and CP's combined total requirements.

IGI indicated that it had been granted a two-year extension to its DOE/FE blanket authorization which expired 1 August 1990 and that it anticipated filing an application for import authorization with volumes and terms specific to the Mobil contract with the DOE/FE shortly.

Washington Natural

Washington Natural is a regulated LDC distributing natural gas to more than 330,000 customers in Washington's Puget Sound area, including

Seattle and the state capital, Olympia. Washington Natural is a wholly-owned subsidiary of Washington Energy Company, a diversified holding company.

In addition to system supply, the LDC stated that it may also utilize the Mobil gas during summer periods for injection into underground storage at the Jackson Prairie Underground Storage Field, of which it is a one-third owner.

In 1988, total energy consumption by Washington Natural's end-use market was 70.5 PJ (66.9 million MMBtu). Total energy consumption by 2003 is anticipated to be 121.9 PJ (115.6 million MMBtu). Customer growth is expected to exceed an average of 19,000 per year through 2000, with increasing per customer usage. Washington Natural's daily firm gas supply requirements are expected to increase by approximately 21 092 to 31 638 GJ (20,000 to 30,000 MMBtu) each year through 1994.

Washington Natural historically purchased all of its gas supply from Northwest under firm service contracts. When Northwest declared itself an open access carrier, Washington Natural elected to retain a firm pipeline sales service of 158 192 GJ (150,000 MMBtu) per day and converted the remainder of its firm sales contract, 156 733 GJ (148,616.55 MMBtu) per day to firm transportation capacity. Washington Natural has determined that, in order to replace the Northwest firm supply for the year commencing October 1989, it must contract for approximately 100 188 GJ (95,000 MMBtu) per day of firm gas supply. Washington Natural indicated that average daily requirements on an annual basis for normal weather are approximately 210 923 GJ (200,000 MMBtu).

Washington Natural stated that its anticipated load factor for the applied-for export licence is at least 75 percent, well in-line with its system load factor. At this load factor, the export by Mobil would account for roughly 3 percent of Washington Natural's total requirements.

Washington Natural stated that an application for import authorization from the DOE/FE for the Mobil purchase had been completed and was to be filed on 31 July 1990, and that it was in possession of a short-term authorization valid until winter 1992 under which the gas could flow.

Each of the three purchasers testified that its forecast and assumptions upon which the forecast was based were realistic and demonstrated a need for the applied-for Canadian gas.

3.5.2 Transportation

The gas would be transported on the Westcoast system to the Huntingdon, British Columbia export point. From the international border, the gas would be transported on Northwest's pipeline system for delivery into the downstream systems of Cascade, IGI and Washington Natural for use by their respective customers.

Mobil has in excess of 1 000 10^3m^3 (35,300.98 MMcf) per day of FS capacity under contract with Westcoast until 31 October 1991. This is sufficient to deliver the initial maximum daily quantity of 736.92 10^3m^3 (26.0 MMcf). Mobil indicated that it intended to rely on the renewal rights provision contained in Article 2.02 of the General Terms and Conditions of Westcoast's *Pipeline Tariff* for firm transportation beyond the above expiry date.

In the U.S., Cascade, IGI, and Washington Natural have sufficient firm capacity contracted on the Northwest system from Sumas, Washington to their respective delivery points. The expiry dates of these transportation contracts are 2014, 2008 and 2004 respectively, all of which are beyond the terms of the applied-for licences.

From the wellhead to the burnertip, no new pipeline facilities would be required to accommodate the proposed exports.

3.5.3 Gas Sales Contracts

The gas to be exported would be sold under three separate arrangements to Cascade, IGI, and Washington Natural at the Huntingdon, British Columbia delivery point in accordance with the terms of the 1 November 1990 Gas Purchase Agreements with Mobil.

Cascade

The initial term of the Mobil / Cascade Gas Purchase Agreement expires 31 October 2000 and would be extended automatically for subsequent two-year periods unless either party gives written notice.

The sale and purchase of gas under the contract is subject to several conditions precedent, including receipt of all Canadian and U.S. regulatory approvals and finalization of all Canadian and U.S. transportation arrangements. These conditions precedent are to be satisfied by 1 November 1990 otherwise either party may terminate the contract by written notice. The gas contract may also be terminated if price arbitration is used more than three times in the first seven years of the gas contract's term.

Cascade has contracted to purchase some 12 631.58 GJ (12,000 MMBtu) per day of gas from Mobil. There are no contractual provisions for Mobil to make best efforts sales above this daily contract quantity ("DCQ"). However, any portion of the DCQ not nominated by Cascade is released to Mobil.

The contract contains a three-part pricing structure consisting of a demand charge, a commodity charge and a reservation fee. The demand charge equals the monthly toll charge on the Westcoast system for gathering, processing and transporting the DCQ to Huntingdon. The commodity charge is the product of the amount of gas delivered and the commodity price. The commodity price is the weighted sum of the following:

- 25 percent of the B.C. Gas residential gas price at the wellhead;
- 25 percent of the price of #6 fuel oil, consistent with environmental regulations, in Seattle;
- 25 percent of the thirty-day spot price for gas laid into Northwest at Sumas, Washington; and,
- 25 percent of the thirty-day spot price for gas laid into Northwest from U.S. supply sources.

The commodity price formula can be renegotiated in any year. If a new commodity price formula cannot be agreed upon by the end of the set 30-day negotiation period, either party may invoke price arbitration. The price arbitration provision involves each party submitting its final offer on the commodity price formula and the arbitrators selecting one of the two offers.

The reservation fee is calculated monthly and is the greater of (i) the product of 18 percent of the commodity price and the sum of the DCQ not taken, or (ii) the product of 9 percent of the commodity price and the DCQ.

IGI

The initial term of the Mobil / IGI gas contract also expires 31 October 2000 and is likewise automatically extended for subsequent two-year periods unless written notice is given.

The conditions precedent and deadline for their completion are the same as in the Mobil / Cascade gas contract. The gas contract can be terminated should price arbitration be used more than three times in the first seven years. Also, should IGI lose two price arbitration rulings prior to the fifth contract year, it may forego the final step-up in gas volumes.

IGI has contracted for initial daily purchases of 5 263.16 GJ (5,000 MMBtu) from Mobil. At the end of the second and at the end of the fifth contract year, this volume would be increased by an additional 5 263.16 GJ (5,000 MMBtu) per day. Best efforts sales above the DCQ are not contractually required but, should IGI not nominate the full DCQ, the remainder is released to Mobil.

The gas contract contains a three-part pricing structure consisting of a demand charge, a commodity charge and a reservation fee. These and provisions regarding the process of renegotiation and arbitration of the commodity price are identical to those in the Mobil / Cascade gas contract.

Washington Natural

Unlike the other gas contracts, the Mobil / Washington Natural gas contract terminates 31 October 2003; it also provides for automatic two-year extensions beyond that date.

The Mobil / Washington Natural gas contract contains the same conditions precedent and deadline for their completion as in the other two gas contracts. The gas contract can also be terminated should price arbitration be used more than three times in the first seven years.

Initial daily purchases under the gas contract are for 10 526.32 GJ (10,000 MMBtu) of gas from

Mobil. Commencing 1 November 1992, the DCQ becomes 15 789.47 GJ (15,000 MMBtu). Best efforts sales above the DCQ are not contractually required but, should Washington Natural not nominate the full DCQ, the remainder is released to Mobil.

Provisions regarding the pricing structure and renegotiation and arbitration of the commodity price are identical to those in the other two gas contracts.

Mobil noted that, as the commodity price in each of the three contracts comprises a bundle of reported British Columbia and Pacific Northwest natural gas and fuel oil prices, the current selling price under the contracts would track the competitive prices available in the marketplace.

3.5.4 Views of the Board

The Board is satisfied that the applicant has adequately demonstrated that the LDC markets of Cascade, IGI, and Washington Natural represent stable long-term markets for Canadian gas. The Board notes in particular that these LDCs are entering into long-term agreements with Mobil to replace the short-term spot sale arrangements that have been in place for the past two years. In addition, Mobil's sales would make up less than 10 percent of the total LDC requirements and, therefore, changes to the LDCs' overall demand should not be reflected wholly on sales by Mobil.

The Board notes that transportation on both the Westcoast and Northwest systems is in place and, given the renewal provisions in Westcoast's *Pipeline Tariff*, is satisfied that it would remain so over the export term.

The Board has reviewed the provisions of the contracts between Mobil and Cascade, IGI, and Washington Natural. The Board is satisfied that the demand charge component of the pricing structure would ensure recovery of fixed Canadian transportation costs associated with transporting the gas to the Huntingdon, British Columbia export point. The Board also notes that the reservation fee would add stability to producer revenues.

The Board is satisfied that the contract provisions would ensure the ability of the contracting parties to respond to changing circumstances in the export market.

The Board has reviewed the gas contracts and has noted that they have been negotiated at arm's length between Mobil and Cascade, IGI, and Washington Natural, and finds that the pricing terms are such that the arrangement is likely to be durable over the contract/licence term. The Board notes that the contractual price is a function of a basket of gas and fuel oil prices on the west coast.

3.6 Disposition

The Board has decided to issue three new gas export licences to Mobil subject to the approval of the Governor in Council.[1] Appendix II outlines the terms and conditions of the three licences, including a condition in each of the three that the term of the licence shall commence on the date that Governor in Council approval is received and shall end on 1 November 1991, unless exports commence under the licences on or before 1 November 1991, in which case the term would end on 31 October 2000 with respect to the sale by Mobil to Cascade and IGI and on 31 October 2003 with respect to the sale by Mobil to Washington Natural. The Board notes that Mobil has agreed to the 1 November 1991 sunset date.

1 Although the application is being made on behalf of the Mobil Oil Canada partnership, the licence, as requested, is being issued to Mobil Oil Canada, Ltd.

Chapter 4

L & J Energy Systems, Inc.

4.1 Application Summary

By application dated 26 March 1990, L & J applied to the Board under Part VI of the Act for a new natural gas export licence with the following terms and conditions:

Term	-	commencing on the date of first deliveries and extending for a term of 15 years.
Point of Export	-	near Iroquois, Ontario.
Maximum Daily Quantity	-	329.6 10^3m^3 (11.7 MMcf)
Maximum Annual Quantity	-	121.3 10^6m^3 (4.28 Bcf)
Maximum Term Quantity	-	1 815.9 10^6m^3 (64.1 Bcf)
Tolerances	-	10 percent per day and 2 percent per year.
	-	any volumes authorized for export which are not actually exported during any year may be exported during the remaining term of the licence subject to the maximum daily volume limitation.[1]

The gas proposed for export would be produced in Alberta from existing pools and fields controlled by Morgan Hydrocarbons Inc. ("Morgan"). The gas would be transported on the NOVA system to the point of interconnection with TransCanada near Empress, Alberta. At this point, L & J would obtain ownership of the gas. From Empress, the gas would be transported on TransCanada's system to the international border near Iroquois, Ontario. The gas would then be shipped on the proposed Iroquois Gas Transmission System ("Iroquois") pipeline on an interruptible basis to the vicinity of L & J's cogeneration facility at Lowville, New York. Local transportation from the Iroquois system to the cogeneration facility would require construction of a short pipeline.

The plant's power output would be sold to Niagara Mohawk and the steam would be sold to Kraft Inc. ("Kraft") for use at its Lowville Philadelphia Cream Cheese plant. The cogeneration facility would be constructed adjacent to the Kraft plant.

4.2 Complaints Procedure

The complaints procedure gives Canadian gas users an opportunity to object to an export proposal on the grounds that they have not had an opportunity to obtain supplies of gas under contract terms and conditions, including price, similar to those contained in the export proposal.

No complaints were received with respect to the L & J export proposal.

4.3 Export Impact Assessment

L & J has adopted the Board's EIA with the caveat that, although L & J supports the conclusions of the Board's analysis, it is not in agreement with the methodology used to reach those conclusions. In its opinion, the methodology used by the Board includes many of the assumptions that were utilized in the former benefit-cost analysis, with which L & J disagreed.

On the basis of its 7 September 1989 EIA, the Board finds that the applied-for export volumes would have little impact on the production,

1 During the hearing, L & J stated that this condition did not make sense and asked that it be deleted from the application.

consumption, and price of gas in Canada, and that Canadian energy users would not experience difficulty in meeting future energy requirements as a result of the proposed export.

4.4 Gas Supply

4.4.1 Supply Contracts

L & J has executed a 15-year Gas Purchase Agreement with Morgan. Under the terms of the gas contract, Morgan has dedicated lands in six areas of Alberta to L & J. Although Morgan has the option to replace or add to the dedicated reserves, it is not contractually obligated to do so.

4.4.2 Reserves

Table 4-1 shows that the Board's estimate of L & J's remaining marketable gas reserves is 20 percent lower than L & J's estimate. The Board's estimate is approximately equal to the applied-for volume.

Table 4-1

Comparison of Estimates of L & J's Contracted Remaining Marketable Gas Reserves with the Applied-for Term Volume

10^6m^3
(Bcf)

L & J[1]	NEB[2]	Applied-for Volume
2 276	1 827	1 816
(80.4)	(64.5)	(64.1)

1. as of August 1990
2. as of December 1989

In its analysis of L & J's contracted gas supply, the Board recognized 12 gas pools in five areas throughout Alberta plus 40 single sections in a Second White Specks multi-field gas pool located in the Werner area. All of the gas is contained in Cretaceous sands, with the exception of one Triassic and one Devonian pool.

The difference between the Board's and L & J's estimates of total reserves is primarily attributable to differences in estimates of reserves for the Werner Second White Specks Pool and the Enchant Arcs Pool.

The Board's estimate of remaining marketable reserves is 18 percent lower than L & J's estimate for the multi-field Second White Specks, primarily as a result of differences in interpretation of net pay in the thin silty sands. In the absence of performance data which supports the higher estimate of net pay submitted by L & J, the Board considers it appropriate to adopt more conservative net pay estimates. The Board concurs with L & J's recovery factor, recognizing that the pool is to be developed on a half-section spacing.

The Board's estimate of remaining marketable reserves is 13 percent lower than L & J's for the Enchant Arcs Pool. The Board's estimate is lower primarily due to its exclusion of reserves which L & J submitted could be drained from lands which are not under Morgan's control. The Board recognizes, however, that additional reserves may be recovered from the dedicated lands depending on future development activity and well performance.

The Board's estimate of reserves is lower than L & J's in the remaining pools due to minor variations in net pay, area, recovery, and surface loss factors.

In summary, the Board's estimate of reserves is lower than that of L & J's and approximately equal to the applied-for volume. However, the Board recognizes the potential for upward revisions to its estimate of reserves for pools in the Werner and Enchant areas.

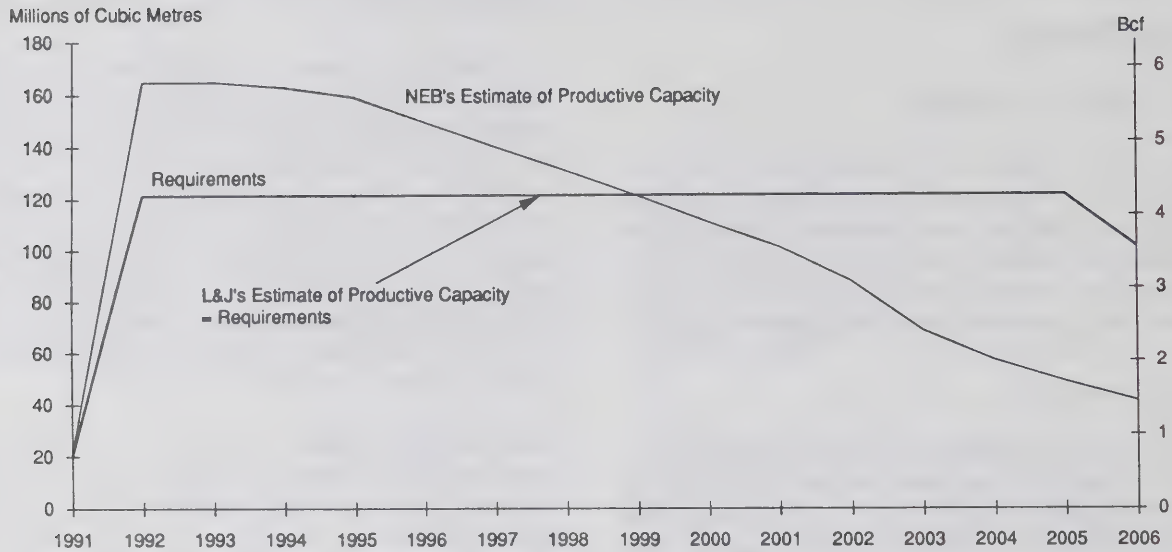
4.4.3 Productive Capacity

Figure 4-1 compares both the Board's and L & J's projections of annual productive capacity with the applied-for requirements. L & J stated that gas required for shrinkage and TransCanada fuel would be purchased or obtained from its uncontracted Alberta gas supply.

L & J's projection of productive capacity is based on a field-by-field forecast which shows it can meet the applied-for requirements throughout the proposed export term. This compares to the

Figure 4-1

COMPARISON OF L&J'S & NEB'S ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY



Board's projection of productive capacity, which indicates adequate gas supply until 1999 and increasing deficiencies in supply relative to requirements thereafter. This divergence in outlook is primarily attributable to the difference between the Board's and L & J's estimates of reserves and is also related to differences in estimates of capability for some specific pools.

Morgan indicated that additional reserves may be developed on its dedicated lands and that it could rely on approximately 992 10^6m^3 (35 Bcf) of currently uncontracted gas reserves should shortfalls in deliverability occur. However, under the terms of the gas contract, Morgan is not obligated to develop additional reserves unless it is economically feasible to do so, and it is not obligated to provide reserves other than those dedicated pursuant to the terms of the contract.

4.4.4 Energy Removal Authorization

Morgan applied to the ERCB for an energy removal permit on 21 March 1990. A decision is anticipated in the spring of 1991.

4.4.5 Views of the Board

The Board is concerned that its estimate of productive capacity does not meet the applied-for requirements beyond 1999, but does recognize the potential for some upward revision of its estimate of gas supply. Although Morgan indicated that shortfalls in deliverability may be alleviated by further development on the dedicated lands or reliance on currently uncontracted reserves, the Board notes that Morgan is not contractually obligated to dedicate additional reserves in the event of supply shortfalls and is not subject to contractual penalties should deficiencies occur. L & J has not made any supply arrangements beyond those with Morgan, and did not provide evidence which indicated that it had plans to supplement supply from Morgan in the event of shortfalls.

In its deliberations, the Board considered L & J's request for a technical conference regarding the dedicated gas supply. L & J had full opportunity to present its supply evidence in the hearing and the Board is of the view that this evidence was adequately canvassed. Accordingly, a technical conference to further clarify the basis for estimates of reserves is not warranted in this circumstance.

4.5 Market and Commercial Arrangements

4.5.1 Market

The gas proposed for export would be used to fuel a 49 MW gas-fired combined-cycle cogeneration facility that L & J plans to construct at Lowville,

New York. L & J is the general partner for the limited partnership of Racine, Megan, and Morgan, and is a single-purpose corporation created for the sole purpose of owning, building, and constructing the Lowville cogeneration facility.

Although Morgan is a part owner of the cogeneration facility, its involvement is limited to that of a minority interest with no operational control. Morgan testified that the gas contract was negotiated at arm's length.

The cogeneration facility would be located adjacent to the Kraft cream cheese processing plant in Lowville, New York. Output from the Kraft plant is marketed throughout the northeastern United States. Niagara Mohawk, the power purchaser, is a gas and electric utility serving most of New York from Lake Erie to the Massachusetts border. Niagara Mohawk serves over 1.4 million electric customers and has a generating capacity of approximately 7,000 MW.

L & J's contractor, Hawker Siddeley Power Engineering Inc., commenced construction of the cogeneration facility on 9 March 1990. The cogeneration facility is expected to be fully operational by March 1992.

L & J stated that it had narrowed the list of project financiers to two and expected financial closing to occur around February 1991. L & J is providing interim financing.

The potential lenders have indicated that they would not break escrow until the Board has decided upon the Part IV (tolling) matters in the GH-5-89 Hearing. L & J has stated that the increased cost to the L & J project resulting from an incremental toll methodology would be more than the project could bear.

All required environmental approvals and permits in the U.S. with respect to the construction and operation of the cogeneration facility have been obtained. Decisions on applications to the ERCB, FERC and DOE/FE affecting this project are currently pending, with the FERC and DOE/FE rulings expected in the fall. QF certification was received 14 October 1988.

L & J forecasts a load factor of 92 to 95 percent for the cogeneration facility. Under New York State Cogeneration Regulations, the facility may operate on No. 2 fuel oil for up to 90 days per year. In the event that capacity on TransCanada is not available in a timely fashion, L & J has negotiated an agreement-in-principle with Western Gas Marketing Limited for interim gas supplies.

4.5.2 Transportation

Within Alberta, the gas would be shipped to Empress on the NOVA system. TransCanada would transport the gas from Empress to Iroquois' system for delivery to the cogeneration facility in Lowville, New York.

Transportation in Alberta has been secured under single-year firm evergreen agreements between NOVA and Morgan.

On 21 March 1990, L & J filed a request with TransCanada for 329 10^3m^3 (11.7 MMcf) per day of firm transportation service to the planned interconnection with Iroquois for a 15-year term commencing 1 November 1992. As L & J requires the capacity by late winter 1992, it also filed with the Board a section 71 application dated 22 March 1990 to obtain the requisite firm transportation capacity on TransCanada. L & J has stated that it is also considering obtaining currently requested capacity should any project in the GH-5-89 application not proceed, or possibly requesting that TransCanada submit an application under section 58 of the Act. L & J has been included in TransCanada's queue for service commencing 1 November 1992 and expects to execute a Precedent Agreement with TransCanada shortly.

L & J entered into a Precedent Agreement, dated 25 May 1990, with Iroquois for interruptible gas transportation service. The term of the agreement has not been finalized, but would be for either 15- or 20-years commencing 1 November 1992. The transportation service being requested would be equivalent to the limited-interruption firm ("LIF") service that TransCanada initially proposed at the outset of the GH-5-89 Hearing and then withdrew. Given the status of the Iroquois application before FERC at the present time, application to FERC for LIF-type service has not yet been made. L & J has stated that, because of the cogeneration facility's geographic location on the Iroquois system, it does not anticipate that interruption of service would be a problem and anticipates, based on discussions with Iroquois, that interruptions would be limited to approximately 15 days per year. The L & J

project is totally dependent on the Iroquois system for delivery of gas.

The 9.4 km lateral from Iroquois to the cogeneration facility would be built, owned, and operated by L & J.

4.5.3 Gas Sales Contract

A gas contract dated 9 March 1990 has been executed by Morgan and L & J. During the hearing, L & J advised the Board that Morgan and itself were presently amending this contract, but that the amendments would not affect its substance.[1]

The gas contract is for a 15-year term commencing with the start of firm deliveries; contains provision for a 5-year extension; and, provides for the daily delivery of up to 326 10^3m^3 (11.7 MMcf) of gas at the interconnection of the NOVA and TransCanada facilities near Empress, Alberta.

The gas contract is subject to several conditions precedent, including: receipt of all Canadian and U.S. regulatory approvals; finalization of all Canadian and U.S. transportation arrangements; satisfaction that buyer has the financial ability to construct the plant; and, identification of dedicated lands. The conditions precedent are to be satisfied by various specified dates otherwise either party may terminate the gas contract.

The gas contract provides for deliveries of start-up gas prior to the commencement of firm deliveries. If deliveries under the gas contract have not commenced by 9 March 1993 then either party may terminate the gas contract.

Under the gas contract, L & J would nominate 100 percent of its gas requirements, up to the MDQ of 326 10^3m^3 (11.7 MMcf), from Morgan. Quantities of gas in excess of requirements, but less than the MDQ, may be nominated by L & J for resale to third parties.

In the event that L & J takes less than 70 percent of the Annual Quantity during a year, Morgan can reduce the MDQ by the percentage by which total quantities purchased by L & J were less than the 70 percent.[2] Should nominations by L & J be less than 60 percent of the Annual Quantity in a given year, then L & J would make a deficiency payment equal to the product of the weighted average of the commodity charge during the year and the difference between 60 percent of the Annual Quantity and the volume of gas delivered.

Should L & J anticipate nominations to be less than the MDQ for an extended period of time then, on L & J's request, Morgan may sell to a third party any portion of the MDQ not taken by L & J.

The gas contract's pricing structure consists of three parts. The first component is the product of the commodity charge and delivered quantities. The commodity charge is adjusted quarterly starting from a base level of $ U.S. 1.52/GJ ($ U.S. 1.60/MMBtu) effective 9 March 1990. Adjustments to the commodity charge would be comprised equally of changes in Niagara Mohawk's avoided energy costs, as provided by the NYSPSC, as well as changes to the gas commodity component of CNG's full requirements Rate Schedule ("RQ Rate Schedule"), which is approved by the FERC. The second component is the product of the Monthly Quantity and the sum of the NOVA Demand Charge for deliveries to Empress and the Supply Reservation Fee.[3] The Supply Reservation Fee is contractually set at $ U.S. 0.19/GJ ($ U.S. 0.20/ MMBtu). L & J is obligated to indemnify Morgan for any penalties imposed by NOVA or TransCanada on Morgan should L & J fail to take delivery of all gas nominated. The last component, which is subtracted from the previous two, is the product of the Monthly Quantity and the sum of the TransCanada Commodity Charge and the TransCanada Fuel Charge.

L & J is to pay for any pressure charges that the Board may apply at the interconnection of TransCanada and Iroquois.

The gas contract allows for renegotiation of the base commodity charge and/or the commodity charge index every second year. If renegotiation is

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1 Subsequent to the close of the hearing, L & J, by letter dated 20 September 1990, provided the Board with its amended and restated Gas Purchase Agreement. The Board is of the view that the substance of the contract was not affected by the amendments.

2 Annual Quantity is defined as the sum of the MDQs for each day of the year less volumes nominated by Buyer but which Seller fails to deliver and less volumes sold to third parties which are deemed to have been sold to Buyer.

3 Monthly Quantity is defined as per Annual Quantity except that it is the sum of the MDQs for each day of the month.

unsuccessful, then either party may request arbitration. The arbitrators' determination is to be based upon the prices received by other Alberta gas producers and the price of gas and other competing fuels in the U.S. northeast.

The gas contract also contains a deferral mechanism designed to accommodate circumstances where the formula-based gas price falls outside a specified range.

L & J submitted that on 1 January 1990, the Alberta border price would have been $ Cdn. 2.55/GJ ($ Cdn. 2.42/MMBtu).

4.5.4 Power Sales Agreement

The proposed sale of electricity from the Lowville cogeneration facility, a QF facility, would be pursuant to the "Agreement" dated 21 November 1987 between L & J and Niagara Mohawk. The power contract shall commence for a term of one year from the date of initial operation and shall continue thereafter until it is cancelled by L & J.

The Lowville plant is a base load facility, requiring Niagara Mohawk to purchase its total net electrical output. Base load operation of the cogeneration facility requires Niagara Mohawk to pay the applicable energy charge, as approved by the NYSPSC, during both peak and off-peak periods. The sale of electricity from the Lowville facility does not require wheeling by third parties.

4.5.5 Curtailment

Union stated that, while NYSPSC decisions appear to have rendered contractual curtailment provisions inoperable, the issue of curtailment persists because there are still provisions for Niagara Mohawk to apply to the NYSPSC to curtail delivery from cogeneration facilities. Union stated further that no evidence had been presented that absolutely assured the Board that there would be no curtailment.

The NYSPSC issued an Order dated 27 June 1989, Case 88-E-081, which rejected, in part, Niagara Mohawk's power contract curtailment clauses with L & J. Case 88-E-081 states that curtailment of deliveries from alternative power producers may be curtailed pursuant to a provision of the PURPA Regulations, "which permit utilities to curtail, when due to operational circumstances purchases from QF's would result in costs greater than those which the utility would incur if it did not make such purchases."[1] Such operational circumstances were found to exist when a utility would curtail generation from its own must-run units during a light load period in order to take generation from APPs. Once curtailed, such units would not be available to generate when load would rise from the low load point toward a day's peak load. Instead of avoiding costs, a utility would incur additional costs in securing substitutes for unavailable must-run generation. To avoid such a situation, § 292.304 (f) permits a utility to curtail deliveries from APPs and continue to operate its own must-run facilities.

The NYSPSC found that no utility had successfully demonstrated that operational circumstances would actually occur, creating negative avoided costs, and that therefore curtailment clauses were premised on assumptions that do not comport with § 292.304 (f).

The NYSPSC found that the utilities, members of the NYPP, assumed that their systems were operating in isolation and that they did not recognize the possibility of off-system sales to other pool members. Utilities would be required to show that the NYPP could not absorb the electricity before they would be allowed to curtail. The NYSPSC stated that, once off-system sales were recognized, the justification for curtailment vanished.[2]

After 1994 the process of bidding should match APP capacity additions to utility capacity needs. The NYSPSC assumed that generation secured through bidding would be dispatchable, enhancing utility capability to alleviate overgeneration situations without incurring curtailments due to operational circumstances.

The NYSPSC found that, because utilities were unable to demonstrate that negative avoided costs due to operational circumstances would exist from the date of 88-E-081 to 1994, and with the commencement of a bidding process in 1994, there would be a match of new sources of generation

1 18 CFR § 292.304 (f) (1)

2 NYSPSC staff analyzed pool-wide operations to assess APP generation state-wide during light load hours. At APP penetration below 5,000 MW, utilities would not be required to curtail delivery from their must-run units. Significant curtailment would be necessary only if 7,000 MW were assumed. Utilities expected only 3,096 MW of APP generation by 1995.

supply to generation need. Consequently, because of the operational flexibility due to greater dispatchability, there is no justification for curtailment after 1994. Since utilities failed to demonstrate they can satisfy conditions established in § 292.304 (f) justifying curtailment, the curtailment clauses were rejected and the utilities were barred from implementing them.

In a further Order dated 12 December 1989, the NYSPSC clarified its Order in Case 88-E-081. Clarification was required to ensure utilities were accorded their § 292.304 rights. The NYSPSC stated that curtailment would not be allowed until prior written approval of curtailment procedures had been obtained, following NYSPSC review of a utility's presentation. To the extent that current contract clauses deviated from the interpretation and implementation of § 292.304 (f) in the NYSPSC's proceedings, the clauses were declared null and void. However, utilities were told that they may include curtailment language which comports with NYSPSC Orders in future contracts, but that they may not expand upon the presumptions established in the NYSPSC's proceedings.

4.5.6 Thermal Energy Sales Agreement

The proposed sale of steam and chilled water from the Lowville cogeneration facility would be pursuant to the Steam and Chilled Water Purchase Agreement, as amended, dated 25 November 1987, between Kraft and L & J. The thermal contract would continue for a period of fifteen years from the date of the first delivery of steam. The contract is conditioned such that it may be extended for successive five-year periods.

Kraft is obligated to purchase sufficient quantities of steam so that the cogeneration facility would maintain its PURPA QF status. The thermal contract provides for the development of alternative steam uses if either party to the contract fails to meet its obligations. A cash penalty clause, requiring payments by Kraft to L & J, is in effect for seven and one-half years from the date of initial steam delivery. The thermal contract also requires L & J to install back-up steam generating equipment to operate an absorption chiller system and intends Kraft to maintain its existing steam generation equipment as back-up.

4.5.7 Views of the Board

The Board is of the view that the downstream markets for the electricity, steam and chilled water produced by the cogeneration facility are secure and that the facility would operate at a high load factor.

The Board notes that project financing for the cogeneration facility is in the process of finalization and that decisions on applications to the ERCB, FERC, and DOE/FE affecting this project are pending. Given the evidence before the Board, these are not considered to be major impediments.

The Board recognizes that transportation in Alberta has been secured and that L & J has been included in TransCanada's 1992 queue and is actively pursuing capacity on TransCanada for earlier deliveries. The Board notes that transportation on Iroquois is required, and is of the view that transportation approvals are sufficiently advanced to conclude that there is a good likelihood that they can be completed.

The Board is satisfied that L & J's export proposal would recover all fixed costs of transportation in Canada. The second component of the pricing terms in the gas contract ensures that demand charges on NOVA would be recouped. The Board notes that L & J is the shipper on TransCanada and is thus directly responsible for all TransCanada demand charges.

The Board is of the view that the pricing provisions contained in the gas contract permit adjustments in the export price to reflect changing market conditions. In particular, the first component of the export price is indexed equally to changes in the current average annual marginal avoided energy cost of Niagara Mohawk and the gas commodity component of CNG's RQ rate schedule. The Board also recognizes the flexibility that exists in the agreement through the inclusion of renegotiation and arbitration provisions. The Board is satisfied that, notwithstanding Morgan's involvement as a limited partner in the cogeneration facility, the gas contract was negotiated at arm's length.

In the Board's view, the gas contract provision that L & J would nominate 100 percent of the plant's requirements up to the MDQ from Morgan,

coupled with the likely prospect that the cogeneration facility would operate at a high load factor, would ensure adequate take levels under the gas purchase agreement.

The Board has noted that the project is not viable with incremental tolls and that it is totally dependent upon the approval of the Iroquois pipeline. Some consideration was given to including a condition in the licence that would terminate the licence in event of unfavourable outcomes of these decisions. The Board, however, decided that the general sunset clause was sufficient to account for these eventualities.

The Board concurs with Union that, from the evidence presented, the Board cannot be absolutely assured that there would be no curtailment of power sales. However, the Board is of the opinion that the likelihood of curtailment of electricity purchases by Niagara Mohawk from L & J is minimal. Furthermore, the possibility of curtailment is unlikely to affect the take of gas proposed for export and, should curtailment occur, it would likely occur for short periods only. In view of this, the Board is of the opinion that curtailment is not a critical issue.

The Board has reviewed the gas contract and has noted that it has been negotiated at arm's length between Morgan and L & J, and that the pricing terms are such that the arrangement is likely to be durable over the contract/licence term.

4.6 Disposition

The Board has decided to issue a new gas export licence to L & J. In order for the licence to take effect, Governor in Council approval thereof is required. Appendix II contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on the date that Governor in Council approval is received and shall end on 1 November 1993, unless exports commence under the licence on or before 1 November 1993, in which case the term would expire 12-years from the commencement of first deliveries. The Board notes that L & J has agreed to the 1 November 1993 sunset date.

For the reasons discussed in section 4.4.5, the Board decided to issue a licence to L & J for a 12-year term rather than for a 15-year term, as requested, based on the Board's assessment of the adequacy of supply.

Disposition

The foregoing chapters constitute our Decisions and Reasons for Decision in respect of the applications heard by the Board pursuant to Hearing Order No. GH-3-90, as amended.

R.B. Horner, Q.C.
Presiding Member

R. Priddle
Member

C. Bélanger
Member

Ottawa, Canada
October, 1990

Appendix I

Technical Discussion of Estimates of Reserves for the Sierra Pine Point A Pool

The Sierra Pine Point A reservoir is one of several isolated bioherms which occur in the Otter Park shale basin of northeastern British Columbia. These bioherms are characterized by steep-sided reefal carbonates and are approximately 400 m (1,300 ft.) thick in the Sierra A pool. Limestone occupies the upper portion (approximately 60 percent) of the Sierra A bioherm, while the lower portion has been dolomitized. An extensive apron surrounds the crestal portion and had gross gas pay up to 46 m (150 ft.). The gas reservoir is underlain by an extensive aquifer.

The limestone has scattered zones of reefoid porosity and caverns have been encountered in two wells. Muddy matrixes and extensive cementation prevented significant porosity development in the limestone facies. However, fracturing is known to exist in the limestone in the Sierra A pool.

The dolomite facies, forming the lower part of the bioherm, is also fractured but is much more porous than the limestone, with porosity ranging up to 15 percent and averaging approximately 10 percent.

The single-well Sierra E pool was discovered in 1980 and is located approximately two km east of the Sierra A pool. It is a separate bioherm, as evidenced by significantly different pressures and gas/water elevations.

As noted in section 3.4.2, Mobil estimated the IGIP for the Sierra A pool using both material balance and volumetric methods and submitted that the material balance method is the more reliable method for estimating IGIP since the pool has over 24-years of pressure-production history. Mobil provided its volumetric estimate for comparative purposes only.

Mobil stated that the results of the material balance study indicate an IGIP of 38 683 $10^6 m^3$ (1,373 Bcf) with no water influx for the Sierra A pool and that a tank-type material balance approach to determine the IGIP was valid. Mobil reported that the gas/water contact measured in late May 1990 showed that the gas/water interface had risen 40.4 m (133 ft.) from the original gas/water contact since production from the pool commenced. Mobil initially suggested that the rate of increase was slowing, but later agreed that it was premature to draw this conclusion.

In conducting the material balance analysis, Mobil applied two methods to account for pressure support arising from water influx. The first method accounts for an infinite-acting aquifer by determining the water influx using the "Hurst van Everdingen" method and adjusting the material balance results to reflect the calculated influx. The results showed that the maximum water influx was relatively small and would not explain the observed rise in the gas/water contact. The second method consisted of using a material balance model incorporating the "Carter-Tracy" method of calculating water influx. This method did not yield a satisfactory match between calculated and observed pressures.

Mobil recognized the apparent conflict between the conclusion that water influx was not a significant factor in the pool performance and both the observed rise in the gas/water contact and increasing water production in the pool.

However, Mobil considered the rise in the gas/water contact to be the result of gas in the apron area and trapped gas in the dead end pore space in the aquifer expanding as the pressure is reduced due to gas production and forcing water into the reef core. Mobil submitted that this supports the view that there is a minimal water influx.

Mobil stated that more than 60 pressure measurements have been taken since the mid-1970s and that these pressures do not show any influence of water influx. Mobil submitted that if water influx in volumes sufficient to fill almost half of the dolomite net pay were occurring, the pressure history would reflect this and the P/Z plot would show some bending upward. Mobil submitted that this was not

evident and that the data therefore supported its material balance reserves estimate.

Mobil also provided a production history plot and concluded that a decline method of analysis cannot be used to estimate recoverable reserves or to confirm the IGIP estimate derived from material balance.

Mobil indicated that it was continuing to attempt to find conclusive evidence as to why the gas/water contact is rising without apparent pressure support from the underlying aquifer. In 1987, Mobil conducted a preliminary reservoir simulation study of the Sierra A pool to determine the behavior of the gas/water contact. However, Mobil points out that this study was conducted using maps that were outdated and is therefore considered to be unreliable. Mobil has recently initiated a comprehensive reservoir simulation study of the pool but the study has been suspended until the geophysical, geological and petrophysical studies incorporating the recently-drilled b-80-C well have been completed. Mobil does not expect that the simulation study would be completed until the end of the first quarter of 1991.

Mobil also provided, for comparative purposes, an estimate of IGIP derived using volumetric methods and stated that this estimate compared favorably with the material balance analysis. The maps used by Mobil to estimate the volumetric reserves were based on a 3-D seismic survey conducted over the Sierra A pool in 1989.

However, since the dolomite surface cannot be mapped directly from seismic, Mobil's dolomite gross pay map was drawn from interpreted seismic data and Mobil cautioned that discretion should be followed in using a net pay map made from this data. Mobil's volumetric estimate is comprised of:

dolomite	20 173 $10^6 m^3$	716 Bcf
limestone	6 607 $10^6 m^3$	234.5 Bcf
residual gas trapped in aquifer	4 632 $10^6 m^3$	164.4 Bcf
Total	31 411 $10^6 m^3$	1,115 Bcf

Originally, Mobil also included an estimate of reserves of 1 214 $10^6 m^3$ (43.1 Bcf) for the Sierra E pool but subsequently indicated that these reserves should be excluded from the A pool estimate because recent data shows limited communication between the A and E pools.

In its volumetric estimate of IGIP for the Sierra A pool, Mobil included a substantial volume of gas, 4 632 $10^6 m^3$ (164.4 Bcf), attributable to "residual gas trapped in the aquifer". Mobil stated that evidence for the existence of residual gas is provided by an aquifer drillstem test in well c-91-D. This test, 46 ft. below the gas/water contact, tested gas too small to measure, along with gassy salt water. To calculate the residual gas volume, Mobil assumed an area equal to the overlying gas pool and 61 m (200 ft.) of aquifer. Mobil's volume of residual gas trapped in the aquifer comprises approximately 15 percent of its volumetric reserves estimate of reserves for the Sierra A pool.

In its evaluation of gas reserves in the limestone portion of the reservoir, Mobil used a porosity cutoff of 0.1 percent. The justification for this low cutoff was based on the assumption that the entire limestone portion is fractured. This resulted in Mobil assigning gas pay to most of the limestone portion of the reservoir.

Mobil estimated the volumes of the caverns by taking the footage of caves penetrated by all wells as a percentage of total drilled footage and then applied this percentage to the majority of the limestone rock volume.

Mobil's recovery factor of 70 percent is its estimate of the expected recovery from the Sierra A pool corresponding to an abandonment pressure of 7 100 kPa. Mobil indicated that it was unable, at this time, to apply separate recovery factors to the volumes of IGIP in the limestone, dolomite and aquifer.

All natural gas from the Sierra A pool is delivered by the Westcoast transmission line to Fort Nelson from the Sierra Plant. Mobil used a total shrinkage factor of 20 percent, of which 5 percent is included as a cost of processing the natural gas.

The Board has considered Mobil's estimates of reserves, derived using both the material balance and volumetric methods and has developed its own estimates of reserves for the pool using similar approaches.

The Board conducted a material balance analysis for the Sierra A pool utilizing the Carter-Tracy

methodology. A number of cases were examined to investigate the potential influence of water influx on the performance of the pool. A reasonable match of the pool's pressure history was achieved with the inclusion of a volume of water influx which was considerably greater than that reflected in Mobil's analysis. This resulted in an estimate of IGIP of 33 116 10^6m^3, as compared to the Mobil estimate of 38 683 10^6m^3. The Board also recognizes that a reasonable pressure match can be achieved with minimal water influx, as suggested by Mobil. However, this interpretation would appear to be inconsistent with the observed 40.4 m (133 ft.) rise in the gas/water interface. The Board notes that Mobil stated that new data confirms the general trend observed previously that the contact is moving upward in proportion to the cumulative withdrawals and is not showing any signs of abating.

The Board is also of the view that recent increases in water-gas ratios for the pool add further support to the premise that water-influx is occurring and influencing pool performance.

The Board concurs with Mobil that the slope of the P/Z plot is linear. However, this evidence alone does not lead the Board to the conclusion that the reservoir is receiving little or no pressure support from the aquifer.

The Board also concurs with Mobil's view that production decline analysis is not applicable to this pool at this time.

The Board has not conducted reservoir simulation studies on the Sierra A pool. Rather, the Board's approach, like Mobil's, has been to use less sophisticated techniques to estimate reserves. The Board recognizes that if the reservoir were modelled using a numerical simulator with suitable capabilities the analysis could lead to somewhat different conclusions regarding the volume of water influx and IGIP for the Sierra A pool. Mobil compared its volumetric estimate of the Sierra A pool reserves to its material balance estimate and indicated that, because the estimates compared favourably, additional support was provided for the material balance analysis.

The Board's volumetric estimate is based in large part on Mobil's mapping of the dolomite facies. The Board concurs with Mobil that discretion should be followed in using a net pay map derived from its seismic interpretation. The Board also adopted Mobil's mapping for the limestone facies despite some concerns regarding Mobil's estimate of total cavern footage and the use of a 0.1 percent porosity cutoff to determine net pay.

With regard to the above comments, the Board's volumetric estimate of IGIP is:

dolomite	21 080 10^6m^3	744 Bcf
limestone	6 465 10^6m^3	228 Bcf
Total	27 545 10^6m^3	972 Bcf

This compares very closely with the Mobil IGIP estimate of 26 779 10^6m^3 for the limestone and dolomite. However, it should be noted that Mobil's volumetric estimate for the limestone and dolomite is approximately 31 percent less than its material balance estimate of reserves for the pool.

The Board agrees with Mobil that Sierra E pool reserves should not be considered in the estimation of reserves for the Sierra A pool.

As noted earlier, Mobil included a trapped gas volume in the aquifer in its volumetric estimate of reserves. In the Board's opinion, residual gas trapped in the aquifer is a somewhat speculative and unproven concept. While very small amounts of gas trapped in the aquifer may exist, the Board is of the view that they would not contribute significantly to pool performance. Mobil did not provide adequate evidence from other pools to support the interpretation that significant volumes of residual gas exist and are recoverable from the underlying aquifer. Consequently, the Board does not attribute any residual gas trapped in the aquifer to its volumetric estimate of reserves for the Sierra A pool.

Mobil used a recovery factor of 70 percent in calculating recoverable reserves for both the dolomite and limestone facies whereas the Board estimated a somewhat higher recovery factor for the dolomite facies and a lower recovery factor for the limestone facies, resulting in an overall recovery factor in the range of 75 percent.

The Board has some doubts as to whether the abandonment pressure of 7 100 kPa estimated by Mobil is achievable and considers 9 000 kPa to be a more likely level based on its analysis. The Board used Mobil's shrinkage factor of 20 percent to determine the marketable gas reserves for the Sierra A pool.

Terms and Conditions of the Licences to be Issued

Terms and Conditions of the Licence to be Issued to Husky Oil Operations Ltd.

1. The term of this Licence shall commence on 1 August 1992 and shall end on 1 November 1993 unless exports commence hereunder on or before 1 November 1993, in which case the term will end on 1 November 2007, except that, should commencement of deliveries occur after 1 November 1992, the term of this Licence shall be 15 years, but shall in no event extend beyond 31 October 2008.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 566 600 cubic metres in any one day;

   (b) 206 800 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 3 154 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that Husky may export in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by two percent.

   (b) As a tolerance, the amount that Husky may export in any calendar month under the authority of this Licence may exceed the quantity allowable during that period by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Cornwall, Ontario.

Terms and Conditions of the Three Licences to be Issued to Mobil Oil Canada, Ltd.

A. Sales to Cascade Natural Gas Corporation.

1. The term of this Licence shall commence on the date of Governor in Council approval hereof and end on 1 November 1991 unless exports commence hereunder on or before 1 November 1991, in which case the term will end on 31 October 2000.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 327 520 cubic metres in any one day;

   (b) 119 540 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 1 195 450 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that Mobil may export under the authority of this Licence may vary from the annual limitations imposed in condition 2 as necessitated by variation in the actual heating conversion factor.

   (b) As a tolerance, the amount that Mobil may export in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (c) As a tolerance, the amount that Mobil may export in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Huntingdon, British Columbia.

B. Sales to IGI Resources, Inc.

1. The term of this Licence shall commence on the date of Governor in Council approval hereof and end on 1 November 1991 unless exports commence hereunder on or before 1 November 1991, in which case the term will end on 31 October 2000.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) for the period commencing on the date of Governor in Council approval hereof and ending on 31 October 1992, 136 470 cubic metres in any one day, or 49 810 000 cubic metres in any consecutive twelve-month period ending on 31 October;

   (b) for the period commencing on 1 November 1992, and ending on 31 October 1995, 272 930 cubic metres in any one day, or 99 620 000 cubic metres in any consecutive twelve-month period ending on 31 October;

   (c) for the period commencing on 1 November 1995, 409 400 cubic metres in any one day, or 149 430 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (d) 1 145 630 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that Mobil may export under the authority of this Licence may vary from the annual limitations imposed in condition 2 as necessitated by variation in the actual heating conversion factor.

   (b) As a tolerance, the amount that Mobil may export in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (c) As a tolerance, the amount that Mobil may export in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Huntingdon, British Columbia.

C. Sales to Washington Natural Gas Company.

1. The term of this Licence shall commence on the date of Governor in Council approval hereof and end on 1 November 1991 unless exports commence hereunder on or before 1 November 1991, in which case the term will end on 31 October 2003.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) for the period commencing on the date of Governor in Council approval hereof and ending on 31 October 1992, 272 930 cubic metres in any one day, or 99 620 000 cubic metres in any consecutive twelve-month period ending on 31 October;

   (b) for the period commencing on 1 November 1992, and ending on 31 October 2003, 409 400 cubic metres in any one day, or 149 430 000 cubic metres in any consecutive twelve-month period ending on 31 October;

   (c) 1 842 980 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that Mobil may export under the authority of this Licence may vary from the annual limitations imposed in condition 2 as necessitated by variation in the actual heating conversion factor.

   (b) As a tolerance, the amount that Mobil may export in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (c) As a tolerance, the amount that Mobil may export in any consecutive twelve-month

period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Huntingdon, British Columbia.

Terms and Conditions of the Licence to be Issued to L & J Energy, Inc.

1. The term of this Licence shall commence on the date of Governor in Council approval hereof or on the date of first deliveries, whichever is the later, and end on 1 November 1993 unless exports commence hereunder on or before 1 November 1993, in which case the term will end 12 years following the first day of the first month succeeding the commencement of firm deliveries.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 329 600 cubic metres in any one day;

   (b) 121 300 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 1 455 600 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that L & J may export in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that L & J may export in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Iroquois, Ontario.